

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

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PUBLIC SERVICE
COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY POWER COMPANY)
d/b/a AMERICAN ELECTRIC POWER FOR)
APPROVAL, TO THE EXTENT NECESSARY,) Case No. 2002-00475
TO TRANSFER FUNCTIONAL CONTROL OF)
TRANSMISSION FACILITIES LOCATED IN)
KENTUCKY TO PJM INTERCONNECTION, L.L.C.)
PURSUANT TO KRS 278.218)

CERTIFICATE OF SERVICE

This is to certify that a true and correct copy of the Prepared Testimony of Robert O. Hinkel on behalf of PJM Interconnection, L.L.C. with attached exhibits and the Prepared Testimony of Andrew L. Ott on behalf of PJM Interconnection, L.L.C. with an attached exhibit, were served as follows:

Originals were deposited in the Night Drop Box on the 14th day of March, 2003, at the:
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, KY 40601

Ten (10) copies to be served via hand-delivery on the 17th day of March, 2003, at the:
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, KY 40601

Copies of the Prepared Testimony were served via U.S. mail, postage pre-paid on the 14th day of March, 2003, upon:

Michael L. Kurtz, Esq.
Boehm, Kurtz & Lowry
36 E. Seventh Street, Suite 2110
Cincinnati, OH 45202
Attorneys for Kentucky Industrial Utility Customers, Inc.

Mark R. Overstreet, Esq.
Stites & Harbison, PLLC
P. O. Box 634
Frankfort, KY 40602-0634
Attorneys for Kentucky Power Company d/b/a American Electric Power

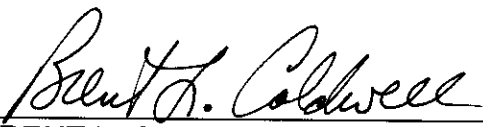
Kevin F. Duffy
American Electric Power Service Corporation
One Riverside Plaza
P. O. Box 16631
Columbus, OH 43216

Elizabeth E. Blackford, Esq.
Assistant Attorney General
Office of Rate Intervention
1024 Capital Center Drive
Frankfort, KY 40601

Richard G. Raff
Public Service Commission of Kentucky
211 Sower Boulevard
Frankfort, KY 40601

Respectfully submitted,

MCBRAYER, MCGINNIS, LESLIE
& KIRKLAND, PLLC
201 E. Main Street, Suite 1000
Lexington, KY 40507
(859) 231-8780


BRENT L. CALDWELL
ATTORNEY FOR
PJM INTERCONNECTION, LLC

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4 **In the Matter of:**)
5 **APPLICATION OF KENTUCKY POWER**)
6 **COMPANY D/B/A AMERICAN ELECTRIC**)
7 **POWER FOR APPROVAL, TO THE**)
8 **EXTENT NECESSARY, TO TRANSFER**) **CASE NO. 2002-00475**
9 **FUNCTIONAL CONTROL OF**)
10 **TRANSMISSION FACILITIES LOCATED**)
11 **IN KENTUCKY TO PJM INTERCONNECTION,**)
12 **L.L.C. PURSUANT TO KRS 278.218**)

13
14
15 **PREPARED TESTIMONY OF**
16 **ROBERT O. HINKEL**
17 **ON BEHALF OF PJM INTERCONNECTION, L.L.C.**
18

19
20 **Q.** Please state your name and business address.

21 **A.** My name is Robert O. Hinkel, and my business address is PJM Interconnection,
22 L.L.C., 955 Jefferson Avenue, Valley Forge Corporate Center, Norristown, Pennsylvania,
23 19403-2497.

24 **Q.** What is your current position with PJM Interconnection, L.L.C. (PJM)?

25 **A.** I have been employed since May, 2002, by PJM as its General Manager of RTO
26 Integration and Coordination. In that capacity, I am responsible for the management of
27 activities associated with the integration of new transmission systems into PJM.
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1 which I assumed my current position. From 1998 to 2001, I was PJM's Manager of
2 Capacity Adequacy Planning. Prior to joining PJM, I was employed for more than 27
3 years by Pennsylvania Power and Light Company (now PPL Electric Utilities) where I
4 worked in various technical and managerial roles in electric system operations, delivery
5 planning, and information services. I earned the degree of Bachelor of Science in
6 Electrical Engineering from Drexel University in 1971. I am a registered Professional
7 Engineer in the Commonwealth of Pennsylvania.

8 **III. DESCRIPTION OF PJM AND PJM WEST**

9 **Q.** Please describe PJM.

10 **A.** PJM has a 75 year history operating the electric transmission grid in its region
11 since 1927, first as an association of transmission owners but more recently, as a truly
12 independent operator of the grid with its own independent Board and governance
13 structure. Since January 1, 1998, PJM has served as the independent system operator, as
14 approved by orders of the FERC, for all or part of the states of New Jersey, Delaware,
15 Maryland, Pennsylvania, Virginia, and the District of Columbia. On December 20, 2002,
16 FERC approved PJM as an RTO, and the FERC approved the expansion of PJM to
17 include PJM West through several orders in 2001 and 2002. In all the areas it serves,
18 PJM's mission as established by its Operating Agreement, and as part of the PJM Board's
19 fiduciary obligations is to promote the safe and reliable operation of the bulk power

1 facilities in the PJM region, the creation and operation of a robust, competitive, and
2 non-discriminatory electric power market in the PJM region, and avoiding undue influence
3 over the operation of the bulk power facilities by any market participant or group of market
4 participants. As discussed below, PJM uses a security-constrained economic dispatch
5 coupled with voluntary energy markets and reliability criteria to provide a reliable and
6 competitive wholesale market. PJM's Board is made up of independent individual
7 representatives from different specialties and includes a former state regulator.

8 **Q.** Please describe PJM West.

9 **A.** On March 15, 2001, PJM and Allegheny Power filed an application at the FERC
10 for the establishment of PJM West and for Allegheny Power to be the initial transmission
11 owner in PJM West. The FERC approved the application, and on April 1, 2002,
12 Allegheny Power transferred functional control of its transmission facilities in
13 Pennsylvania, Maryland, Virginia, West Virginia, and Ohio to PJM. PJM West is a
14 separate control zone to recognize that it operates under the reliability rules of the East
15 Central Area Reliability Coordinating Council (ECAR). Although PJM West is a
16 separate control zone, it is also part of a single energy market, and a single security-
17 constrained economic dispatch, with the pre-existing PJM control area. Participants in
18 PJM West are subject to the PJM Open Access Transmission Tariff and PJM Operating
19 Agreement, including the PJM market rules, Regional Transmission Expansion Planning

1 Process, generation interconnection procedures, Market Monitoring Plan, and governance
2 structure. In addition to being established to accommodate different reliability structures,
3 as discussed below, the PJM West agreements are designed so that additional
4 transmission owners could join PJM while recognizing and accommodating these
5 different reliability approaches.

6

7

IV. BENEFITS OF JOINING PJM

8 **Q.** Please summarize the primary benefits arising from AEP's participation in PJM.

9 **A.** As discussed in more detail below, PJM provides a liquid wholesale energy
10 market, reliable electric system operations, proven regional planning process, well-
11 structured generation interconnection procedure, effective market monitor, and
12 independent governance. Moreover, the addition of AEP to PJM is a critical path
13 condition to moving forward with developing and implementing the Common Market
14 with Midwest ISO.

15

16 **Independence**

17 **Q.** Please describe PJM's governance structure.

18 **A.** PJM has a two tiered governance structure, in which the Board of Managers is
19 advised by the Members Committee. PJM is managed by its independent Board of

1 Managers, which has as one of its primary mandates the responsibility to ensure that no
2 market participant or group of market participants has undue influence over the operation
3 of the bulk power facilities or markets in the PJM region. PJM's independent board is
4 responsible for all aspects of PJM's operations and has exclusive authority to amend the
5 PJM Tariff and the reliability assurance agreements (discussed below). PJM also has an
6 extensive and active stakeholder process. The PJM Members Committee advises the Board
7 on most matters, while the Reliability Committees (discussed below) advise the Board on
8 reliability matters. The Members Committee has numerous subcommittees and working
9 groups, in which PJM staff members work with stakeholders to develop proposals to
10 improve PJM's rules and operations. In most cases, including reliability matters, the
11 actions of the stakeholder groups are only advisory, and the PJM Board has final
12 authority to accept, reject, or modify the stakeholders' recommendations. Changes to the
13 PJM Operating Agreement (which includes the energy market rules) require approval by
14 the Members Committee. But even when such approval has not been forthcoming, the
15 PJM Board has on several occasions exercised its independence by filing unilaterally at
16 the FERC to amend the market rules. For example, the PJM Board moved forward to
17 independently propose a demand side response program which received full state
18 commission support once it became clear that the stakeholder Members of PJM were not
19 able to resolve their differences concerning such a program.

1 **Q.** How do state commissions and consumer advocates participate in PJM?

2 **A.** Commissioners and their staffs actively participate in PJM's stakeholder
3 processes. The PJM Board of Managers meets on a regular basis with the state
4 commissions in the existing region under a Memorandum of Understanding that provides
5 a direct line of communication between the state commissions and the PJM Board of
6 Managers. Moreover, the regulatory staff of the state commissions as well as the
7 consumer advocates offices actively participate in PJM's Members Committee and other
8 PJM committee and working group activities. The consumer advocates are voting
9 members of PJM, while the existing state commissions have chosen on their own to
10 participate as non-voting ex-officio members. The current PJM member commissions are
11 currently involved in discussions with the new state commission about how to interact
12 with PJM in the future.

13 **Q.** What are the benefits of PJM's governance structure?

14 **A.** PJM's active, well-established stakeholder process gives electric market
15 participants and other stakeholders a greater voice in the day-to-day issues that affect the
16 markets and reliability. That level of input is not likely to be available outside an ISO or
17 RTO. Equally important, the independence of the PJM Board ensures that no market
18 participant receives an undue advantage.

19 **Energy Market**

1 Please describe PJM's wholesale energy market.

2 A. PJM operates both a day-ahead and real-time wholesale energy market. Participation
3 in these markets is voluntary: market participants can self schedule to meet their native
4 load obligations, engage in bilateral transactions, or may choose to transact in PJM's
5 wholesale energy market. The spot market is used as a clearing market of last resort with
6 approximately one third of the total energy market transactions occurring in the spot
7 market. As the Attachment shows the spot market accounted for 18% of the energy
8 market in 2000, 21% in 2001. In 2002 the spot market accounted for 38% of the total
9 energy market in 2002. *See* Attachment A. In short, most transactions occur as they do
10 today---through self-scheduling or bilateral contracts. The spot market however provides
11 critical price transparency that allows state commissions and market participants to
12 "benchmark" the prudence of those arrangements. In the day-ahead market, sellers
13 submit offers to sell and buyers identify their loads and any maximum prices at which
14 they will elect not to participate in the day-ahead market. PJM uses this information and
15 its analysis of expected system conditions to calculate the clearing or "marginal" price at
16 each load and generation bus for each hour of the following day. These marginal prices,
17 varying by location, are known as locational marginal prices (LMP). Participants in the
18 day-ahead market (which is voluntary) are then obligated to sell or purchase energy in
19 real-time at the prices established in the day-ahead market. For the real-time market,

1 PJM calculates LMPs every five minutes based on actual system conditions and PJM's
2 dispatch of generation resources in economic merit order (based on their price offers) to
3 keep supply and demand in balance. However, the real-time prices affect only buyers
4 and sellers that chose not to participate in the day-ahead market or that deviated from
5 their day-ahead commitments.

6 **Q.** What benefits are provided by the PJM wholesale energy markets?

7 **A.** PJM operates the largest and most liquid wholesale energy market in the country,
8 as shown in the chart the PJM West hub is consistently the most liquid hub for 2002, with
9 liquidity exceeding 20,000 GWh in the third quarter 2002. *See* Attachment B. PJM's
10 day-ahead market allows market participants to lock-in their sale and purchase prices a
11 day in advance, and the LMPs resulting from the market provide valuable price signals
12 that encourage the construction of transmission and generation additions at the places on
13 the grid where they are most needed. Moreover, the PJM market provides the foundation
14 for further customer-oriented advances. For example, as noted above, PJM has
15 implemented a demand response program, with both emergency and economic
16 components, that is integrated with the regional energy market. Qualified participants, by
17 reducing load, can provide the same benefit to the grid as a generator that produces
18 energy, and therefore can receive similar LMP-based payments under the economic
19 demand response program. A regional program, such as PJM's, is able to capture more of

1 the consumer welfare benefits available from demand response than a single-utility
2 program, operating in a small area, could accomplish. This program is available both for
3 industrial load as well as a pilot for residential load.

4 **Congestion Management**

5 **Q.** How does PJM manage transmission congestion?

6 **A.** PJM uses the LMPs calculated in the wholesale energy market as an economic
7 means of managing transmission congestion. Specifically, when there is congestion on
8 the transmission system, transmission customers have the option of avoiding curtailment
9 by agreeing to pay transmission congestion charges, generally calculated as the difference
10 in LMPs on either side of the constrained transmission element. LMP is an effective
11 congestion management tool because it sends price signals that alleviate congestion by
12 providing effective signals that allow the market participants to respond efficiently, such
13 as providing construction of new generation and demand response initiatives.

14 **Q.** What are the benefits from LMP-based congestion management?

15 **A.** With LMP, only those entities causing congestion pay the increased charges. This
16 avoids socialization of the costs. Moreover, transmission customers can use the day-
17 ahead market to lock-in their congestion charges, just as market participants use that
18 market to lock-in their LMPs. In addition, similar to the price signals provided by the
19 energy market, LMP-based transmission congestion charges send price signals for

1 transmission or generation solutions to eliminate the congestion on a long-term basis.
2 Under an LMP system, market participants have greater commercial flexibility in
3 arranging transactions. Market participants have the ability to signal whether they are
4 willing to buy their way through transmission constraints. The FERC has recognized that
5 large LMP-based markets are likely to create greater trading opportunities and increase
6 overall efficiency. The FERC cited the potential market benefits of PJM's expansion
7 when it recently approved PJM as an RTO.

8 **Q.** Can a load serving entity hedge itself from increased congestion costs?

9 **A.** Yes. A Financial Transmission Rights (FTR) provides a hedge or insurance
10 policy against payment of congestion costs. Presently FTRs are allocated to firm and
11 network transmission service customers on an annual basis, in recognition of the fact that
12 they pay the fixed cost of the transmission system. A monthly auction is held to allow
13 FTR holders to sell to market participants – this monthly exchange is scheduled to be
14 replaced by an annual FTR Auction mechanism. Subject to final approvals by the FERC
15 the annual FTR auction is expected to be implemented in April, 2003 for the 2003/2004
16 planning period. The FTR auction will create a more robust FTR market in PJM, and
17 provide additional opportunities for load servers to obtain FTRs to meet their portfolio
18 needs. Also, Network Access Service customers would have the ability to voluntarily
19 resell their FTRs when others value them more highly. Because market participants will

1 see and be responsible for the full effect of their decisions on congestion costs, each have
2 an incentive to manage its own transactions in a way that is consistent with a least-cost
3 dispatch consistent with reliable system operations.

4 **Reliable Electric System Operations**

5 **Q.** How does PJM provide for the reliable operation of the electric system?

6 **A.** PJM provides for both the short-term and long-term reliability of the transmission
7 system. PJM ensures short-term reliability by: 1) receiving, confirming, and
8 implementing all interchange schedules; 2) ordering redispatch of generators connected
9 to PJM-controlled transmission facilities; 3) approving all scheduled outages of
10 transmission facilities; 4) scheduling generator maintenance outages; 5) monitoring the
11 electrical system on a real-time basis; 6) implementing emergency procedures as required
12 to maintain system reliability; and 7) serving as the North American Electric Reliability
13 Council (“NERC”) Reliability Coordinator for the PJM / PJM West region. Attachment C
14 (Operations Summary Summer 2002) provides operating data for the summer of 2002 to
15 demonstrate the integration of PJM markets and reliability activities during peak load
16 conditions, and shows that PJM met and exceeded NERC performance standards (CPS 1
17 and 2) for the peak summer months of June and July 2002. PJM maintains long-term
18 reliability by utilizing reliability standards within the long-term planning process, which
19 is described below.

1 The NERC has approved PJM Reliability Coordination plans for transmission
2 service (Day 1) activities. Pursuant to NERC approval, PJM assumed the role of
3 Reliability Coordinator for the AEP, ComEd, Dayton Power and Light, Ohio Valley
4 Electric Cooperative and Duquesne Light electrical systems on February 1, 2003.
5 Reliability coordination plans for market integration (Day 2) are under development. The
6 Day 2 Plan will address how congestion between PJM and Midwest ISO will be handled
7 prior to the Common Market, and after the Common Market is developed.

8 **Regional Planning**

9 **Q.** Please explain the benefits of the PJM planning process?

10 **A.** By ensuring continued reliability and promoting new competitive alternatives.
11 PJM conducts a regional generation and transmission planning process that is open and
12 transparent and that is expressly focused on the public interest and consumer benefits.
13 PJM, which is nearing the completion of its second annual regional plan, has more
14 experience with regional planning than any other ISO or RTO. As a result of the regional
15 planning process and generation interconnection process (described below) over 7,000
16 MW of new generation has been placed in service since 1999, over 40,000 megawatts of
17 additional generation (including projects in PJM West) are now currently being studied,
18 and \$726 million of transmission upgrades are approved by the Board of Managers (\$200
19 million are baseline upgrades that are the responsibility of the Transmission Owners and

1 the remainder are the direct interconnection facilities and network upgrades required for
2 generation projects that are the responsibility of the developer). These substantial
3 additions to the bulk power facilities in PJM increase reliability and contribute to a robust
4 wholesale market. Looking forward, PJM's open and non-discriminatory planning
5 process will identify and facilitate the most efficient changes to the bulk power market—
6 regardless of whether those are generation solutions, transmission solutions, or demand
7 response solutions. PJM has no financial interest in any of those approaches and will not
8 favor one over any other. A single utility acting on its own cannot provide the same
9 assurances or efficiencies.

10 Regional planning with Midwest ISO will be coordinated in order to allow
11 stakeholders to have regular input. Various PJM and Midwest ISO Groups are currently
12 working on the integration of individual planning processes to form a single, regional
13 transmission expansion planning process, which will include provisions for an ITC. The
14 development of a transmission baseline model is presently underway to provide a model
15 of the system as it exists today and to form the basis for additional analysis. The
16 deliverability of existing generation will be tested in coordination with the development
17 of a resource adequacy construct. We have developed the model and are presently
18 working to complete the analysis.

1 The Regional Transmission Expansion Planning Process provides a methodology
2 for the following: 1) coordinating planning across multiple transmission systems; 2)
3 evaluating alternative solutions including transmission, generation and load options; 3)
4 reflecting broad stakeholder input to the process; 4) incorporating the impacts of
5 operating concerns and congestion; and 5) resolution of seams issues.

6 **Generation Interconnection**

7 **Q.** What are the benefits of PJM's generation interconnection process?

8 **A.** PJM and its stakeholders have developed detailed, non-discriminatory rules and
9 procedures for the interconnection of new generators to the transmission grid. Because
10 PJM's interconnection procedures were the first of their kind to be approved by the
11 FERC, and because a large number of prospective projects have taken advantage of these
12 rules in the three years since the rules became effective, PJM has significant experience
13 with such procedures. Because PJM's rules and procedures are clear, well-established,
14 transparent, and non-discriminatory, they make the PJM region an attractive location for
15 siting generation projects. This is demonstrated by the large number of new capacity
16 projects presently in the PJM Interconnection queue (where position is determined by
17 date of the Interconnection Request) for review and finalization. *See Attachment D.* The
18 process benefits consumers in the region, by ensuring supply adequacy and competitive
19 wholesale prices.

1 **Market Monitoring**

2 **Q.** What are the benefits of PJM's market monitoring function?

3 **A.** PJM's Market Monitoring Unit (MMU) provides close, well-informed, and
4 continuous scrutiny of the markets PJM administers. Pursuant to the market monitoring
5 plan in PJM's Tariff, the FERC and state commissions have called upon PJM's MMU for
6 unbiased factual reports of market conditions and events. In addition, the MMU
7 publishes a comprehensive "State of the Market" Report each year and provides personal
8 briefings upon request to each state commission on the report and analysis. Because the
9 MMU is part of the independent entity that administers the markets, the MMU is on the
10 "front lines," and is in a position to perceive at an early stage trends or patterns of
11 conduct that may lead to exercises of market power or abuses. The MMU's focus,
12 however, is on the markets and market participants in the PJM region.

13 The MMU has conducted investigations and issued reports at the request of the
14 states. The MMU has authority, through the PJM tariff to discontinue actions that the
15 MMU believe violate the PJM Tariff, the PJM Operating Agreement, the Reliability
16 Assurance Agreement, the PJM Manuals, or other rules, standards, practices, or
17 procedures concerning the operation of the PJM market. These demand letters are copied
18 to the state commissions, the state attorney general, the U.S. Department of Justice and to
19 FERC.

1 If AEP joins PJM, this commission will have the benefit of the MMU monitoring
2 transactions in AEP's service territory and can call on the MMU to assist the Commission
3 in critical fact gathering and analysis for the commission to use in investigations or
4 proceedings.

5 **Q.** Does PJM provide any other oversight?

6 **A.** Yes. Consistent with PJM's basic mandate, PJM oversees transmission
7 operations in its region. The FERC recently enhanced PJM's role in this area, approving
8 detailed procedures for PJM's review of maintenance outage scheduling and facility
9 ratings by transmission owners. Such oversight provides greater assurance to consumers
10 that transmission owners are not using their control over transmission to change
11 competitive outcomes. This level of scrutiny is not available for utilities that do not join
12 an ISO or RTO.

13 **Q.** Are you saying that PJM is perfect and needs no improvement?

14 **A.** Not at all. PJM is constantly evolving. Since its inception as an independent
15 entity, PJM has sponsored over 200 changes to its Operating Agreement and tariffs to
16 further refine the marketplace and meet state commission and other needs. We are
17 committed to further reforms to develop a more robust demand side response market and
18 continue to search out reforms to ensure the maintenance of reliability through capacity

1 markets. The input from the state commissions is a critical aspect of all of these
2 developments and is welcomed throughout the organization.

3

4 **V. IMPLEMENTATION SCHEDULE**

5 **Q.** Please define Day 1 as it relates to implementation of the former Alliance
6 companies into the PJM marketplace.

7 **A.** On “Day 1”, subject to regulatory approval, PJM will become the provider of
8 transmission service for AEP’s customers. PJM will initiate this service in accordance
9 with the PJM Open Access Transmission Tariff. PJM will also provide reliability
10 coordination for AEP on Day 1. There will be an implementation of a single through and
11 out rate and a true up will be applied to offset transmission owner lost revenues. Services
12 that will be initiated on Day1 include the following: 1) Open Access Same Time
13 Information System (OASIS) operation for transmission service coordination; 2)
14 calculation of Available Transfer Capability / Available Flowgate Capability (ATC/AFC)
15 data for the integrated transmission system; 3) energy transaction tagging and scheduling
16 in accordance with NERC tagging and scheduling protocols; 4) billing and settlements
17 support for transmission system utilization; and 5) NERC Reliability Coordination.

18 **Q.** Please define Day 2 as it relates to the implementation process.

1 **A.** The PJM energy market functions will be implemented and all wholesale energy
2 and ancillary services functions will be administered by PJM under the PJM Operating
3 Agreement and PJM OATT. On Day 2, PJM customers of PJM will be able to participate
4 in the PJM markets.

5 **Q.** Please explain Day 1 and Day 2 as applied to AEP and Commonwealth Edison
6 (ComEd).

7 **A.** AEP and ComEd will be integrated into the PJM Transmission Service on what is
8 referred to as Day 1 and market integration will occur on Day 2. The implementation
9 schedule developed in concert with the December 11, 2002 PJM filing with the FERC
10 (Docket No. ER03-262) on market growth. Under this implementation plan, Day 1 was
11 scheduled for March 1, 2003. Day 2 was scheduled to occur sixty days following Day 1,
12 on May 1, 2003. PJM has worked diligently to complete the systems work required for
13 the market integration and PJM is prepared to deliver its promise on time and on budget.
14 PJM recently announced an extension to this schedule based on legislative activities in
15 Virginia and the absence of definitive guidance from the FERC on the December 11,
16 2002 filing. PJM is working with the AEP, Dayton Power and Light and Commonwealth
17 Edison Company to modify the implementation schedule in light of these changes.

18 **Q.** Were there other considerations in establishing the timeline for integration of
19 AEP?

1 A. The timeline was established to satisfy the nine conditions included in the FERC's
2 July 31, 2002 Alliance Order.

3 Q. What actions have been taken by PJM to address the nine conditions?

4 A. PJM has taken the following actions to address the nine conditions contained in
5 FERC's July 31, 2002, order:

6 **Common Market Must Be Implemented by October 1, 2004**

7 The FERC's first condition is that the Common Market be implemented by October 1,
8 2004. To achieve this condition, PJM and Midwest ISO agreed to: 1) integrate all the
9 former Alliance companies during 2003; 2) resolve and fully implement solutions to all
10 seams issues; 3) conform the markets in Midwest ISO and PJM to the final Order on
11 SMD; 4) work to eliminate transmission rate pancaking throughout the combined
12 operating territories of the two RTOs; and 5) implement a
13 functional enhanced market portal for single access and one stop shopping across the
14 combined RTOs.

15 **ITC Conditions**

16 The FERC's second, third and fourth conditions related to Independent
17 Transmission Companies (ITCs). This is an issue that for the most part did not directly
18 involved PJM; instead, the parties to the ITC agreement filed an MOU at the FERC in

1 June 2002. PJM has filed a pro forma ITC agreement in accordance with FERC
2 directives.

3 **Joint Reliability Plan**

4 The fifth condition is that NERC must approve the joint Midwest ISO/PJM reliability
5 plan. On November 5, 2002, NERC submitted an initial report to the FERC on the PJM
6 and Midwest ISO Reliability Plan. NERC reported that it approved the first phase PJM
7 and Midwest ISO expansions, concerning changes in the geographic boundaries of the
8 respective regions for which PJM and the Midwest ISO serve as the regional reliability
9 coordinator. Therefore, NERC has approved the PJM expansion plan necessary for AEP
10 and ComEd to transfer functional control of their transmission facilities to PJM, until the
11 start of expanded PJM market operations. Expansion of the PJM market to include AEP
12 and each of the new PJM Companies will not occur until NERC approves the additional
13 reliability plans developed in connection with that expansion. PJM plans to present to
14 NERC with the Midwest ISO an updated reliability coordination plan that includes a
15 congestion management proposal. This plan fully addresses any reliability and
16 operational concerns associated with loop flows between RTOs with separate LMP based
17 markets to perform congestion management or between RTOs where only one RTO is
18 utilizing an LMP based market for congestion management.

1 The Midwest ISO and PJM are working together and will present implementation
2 plans for the congestion management solutions for regional and NERC endorsement prior
3 to market operation in either the PJM or Midwest IOS regions. Training, tests, and drills
4 of the congestion management solutions will be conducted prior to final implementation.
5 Midwest ISO/PJM will improve upon the processes when areas for improvement are
6 identified. A joint operating agreement between PJM and the Midwest ISO will be filed
7 with the FERC prior to commencement of market operations.

8

9 **Through and Out Rates**

10 The FERC's sixth condition is that a solution addressing the "through and out"
11 rates between Midwest ISO and PJM must be developed by September 16, 2002. PJM
12 and Midwest ISO committed to using the Single Market Design Forum (SMDF) to allow
13 stakeholders and transmission owners an opportunity to resolve this issue. To date the
14 PJM/Midwest ISO Single Market Design Forum has worked to develop joint market
15 business rules and an on-going schedule of stakeholder meetings is in progress to
16 continue to develop and refine business rules and processes for the Common Market.

17 Also the FERC is currently reviewing the regional through and out rate for
18 transactions involving both PJM and MISO in a pending Federal Power Act 206

1 proceeding (Docket No. EL02-111-000). Recently, the FERC issued an order stating that
2 an initial decision on this matter is expected by March 28, 2003.

3 **“Islands” Issue**

4 The FERC’s seventh condition is that Alliance companies seeking to join PJM
5 must address issues about “island” problem of Wisconsin and Michigan. To date, the
6 parties have held two meetings to discuss potential settlement of the “hold harmless”
7 issues with no resolution and at the request of the parties an Administrative Law Judge
8 (ALJ) was appointed to expedite and facilitate the discussions by conducting an
9 Alternative Dispute Resolution. The ALJ has determined that a fundamental question is
10 what is the meaning of “hold harmless” and is seeking clarification from the FERC of
11 this term, as specified in the Status Report to the FERC, filed on January 23, 2003 by the
12 Settlement Judge. The resolution of this issue has an impact on Kentucky since, under
13 some scenarios posed by Michigan and Wisconsin utilities, Kentucky utilities and/or
14 customers would have to pay for loop flows on the Michigan transmission system but
15 receive no concomitant payment for loop flows caused by Michigan and Wisconsin
16 utilities on the Kentucky transmission system.

17 **FERC Reporting and Participation**

FERC's eighth condition is that the parties must file an implementation plan and frequent progress reports. The final condition is that the FERC staff must participate in the process. PJM and the Midwest ISO have complied with conditions eight and nine.

VII. COMMON MARKET

Q. Please describe the Common Market.

A. On January 18, 2002, PJM and Midwest ISO entered a letter of intent to develop a Common Market. The Common Market will provide a one stop shop for customers to procure energy and transmission services from both RTOs. The Common Market will allow for single set of market rules and a single approach to managing congestion. The "common market portal" or "Market Interface" will provide a transparent mechanism for participants to perform transactions in either the PJM or Midwest ISO market. In bundled states the Common Market will allow for more efficient dispatch of generation which will result in lower costs to consumers. Also, because the markets are voluntary the state commissions in bundled states will retain their authority to review portfolio and utility buying decisions through either fuel adjustment clauses or base rate proceedings.

Q. Why is AEP's membership in PJM essential to the development of the Common Market?

1 **A.** Prior to the choices of the former Alliance companies to join PJM and Midwest
2 ISO the Common Market was not possible since the two RTOs were not contiguous. The
3 Common Market will result in a large robust market for the buying and selling of
4 electricity and will serve to advance the restructuring of the wholesale electric market in
5 the U.S. AEP's operating companies are located in Indiana, Kentucky, Michigan, Ohio,
6 Tennessee, Virginia and West Virginia and serve more than 20,000 megawatts of peak
7 demand, as such, AEP is a critical piece of the Common Market. If AEP does not
8 integrate into PJM, then the timeline for the Common Market will be set back
9 significantly. The integration of AEP into PJM is a necessary precursor for the Common
10 Market to support a complete geographic grid system.

11 **Q.** What process is in place to develop a rate for service through and out of the
12 combined region?

13 **A.** In this regard, the FERC initiated an investigation under Section 206 of the
14 Federal Power Act on Midwest ISO/PJM rates and feedback is expected by the end of
15 April. The Hearings were held in December 2002 and January 2003. The issues being
16 addressed in this proceeding include the de-pancaking or rates for the new companies to
17 be joining PJM, the test year to use in calculating the new de-pancaked rate and the
18 allocation of lost revenues.

1 **Q.** When will PJM and the Midwest ISO analyze changes in loop flow and
2 congestion resulting from the new configuration and post the expected financial and
3 operational impacts on their websites prior to adding new members?

4 **A.** PJM and Midwest ISO are working with the NERC community and stakeholders
5 to develop a mechanism to address inter-regional congestion management. Workshops
6 are being held to discuss the alternatives under consideration and to solicit stakeholder
7 input. The proposed alternatives are outlined in a white paper. The second draft version
8 of this whitepaper is provided in Attachment E.

9 **VII. OTHER OBLIGATIONS**

10 **Q.** Please describe any other obligations that AEP will face as a result of
11 participation in PJM.

12 **A.** All of the PJM services that I discussed above involve staff, facilities, information
13 systems, and other costs. Attachment F (market growth program budget) provides a
14 summary of anticipated implementation project costs by broad project areas. Under the
15 implementation agreements signed by the joining transmission owners, the expense
16 portions of the expansion costs are borne by the transmission owners while the capital
17 project costs are included in PJM's overall capital budget with the costs recovered from
18 all PJM participants.

1 For the most part, PJM recovers these costs through the administrative cost
2 recovery provisions in Schedule 9 of its tariff. PJM has unbundled these costs, so that
3 PJM members only pay for the PJM services they use. Moreover, because PJM already
4 has extended its markets and operations to include Allegheny Power, PJM can add AEP
5 to the PJM markets at comparatively little cost. As a transmission customer, AEP also
6 would be subject to the obligations set forth in the other ancillary service schedules to
7 PJM's Tariff, including those in Schedule 2, concerning reactive supply and voltage
8 control, Schedule 3, concerning regulation and frequency

9 PJM is well along on its systems development effort and is on time and on budget.
10 For this phased market expansion, PJM is following the same incremental systems
11 expansion and upgrade template that PJM successfully applied just last year for
12 Allegheny Power. PJM is very familiar with the potential vendors, alternatives, and costs,
13 having just gone through a similar process, which PJM completed on budget. Notably,
14 the approach used here allows PJM to implement a market in an area that does not now
15 have one, at a fraction of the cost of approaches that do not leverage an existing market.
16 Because PJM is leveraging its existing systems, the incremental cost per unit of load is
17 very favorable, and will enable PJM to reduce its administrative charges by a substantial
18 margin below what they would have been without the expansion.

19 **Q.** Does this complete your testimony?

1 **A.** Yes, it does.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY POWER COMPANY)
d/b/a AMERICAN ELECTRIC POWER FOR)
APPROVAL, TO THE EXTENT NECESSARY,) Case No. 2002-00475
TO TRANSFER FUNCTIONAL CONTROL OF)
TRANSMISSION FACILITIES LOCATED IN)
KENTUCKY TO PJM INTERCONNECTION, L.L.C.)
PURSUANT TO KRS 278.218)

AFFIDAVIT

Robert O. Hinkel, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

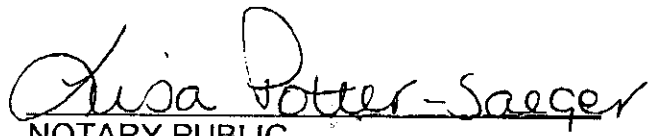

ROBERT O. HINKEL

STATE OF PA)
COUNTY OF Montgomery)

SUBSCRIBED, SWORN TO AND ACKNOWLEDGED before me, a Notary Public, by Robert O. Hinkel, this 14th day of March, 2003.

My commission expires: March 31, 2003

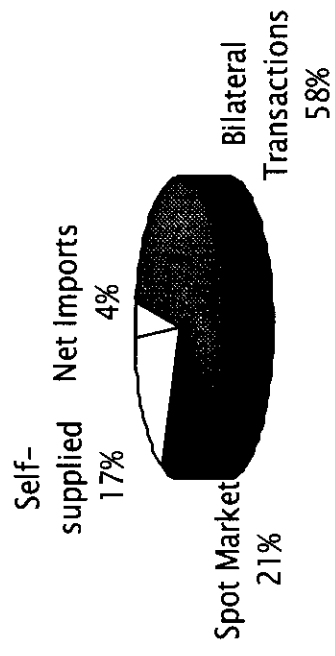
Notarial Seal
Lisa Potter-Saeger, Notary Public
Lower Providence Twp., Montgomery County
My Commission Expires Mar. 31, 2003
Member, Pennsylvania Association of Notaries


NOTARY PUBLIC

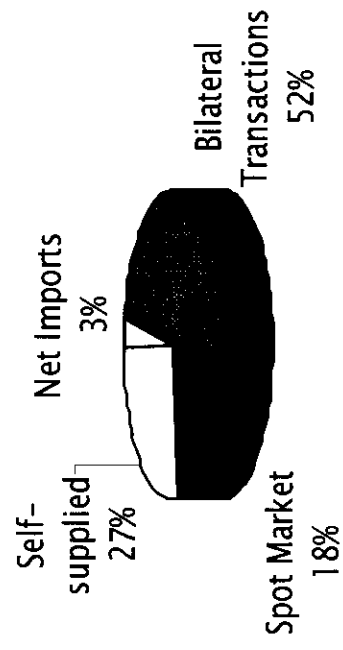
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Energy Market

2001 Energy Market

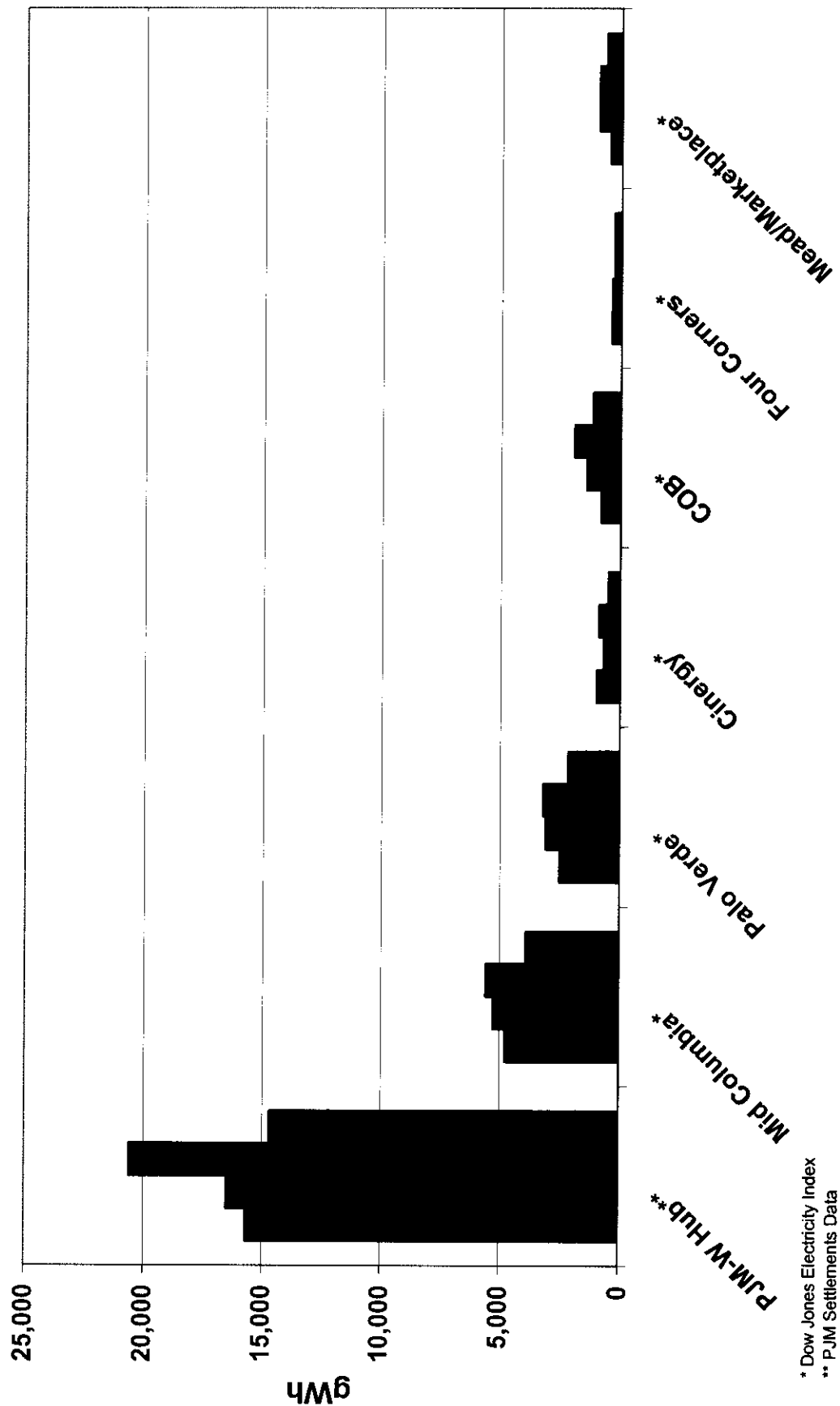


2000 Energy Market



January 2003

Liquidity at U.S. Hubs

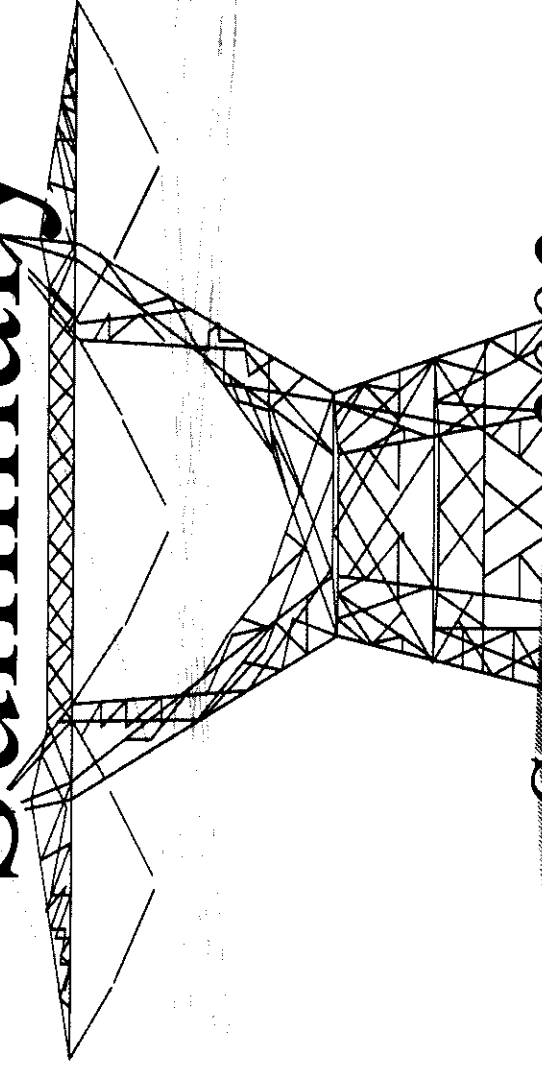


* Dow Jones Electricity Index

** PJM Settlements Data

System Operations

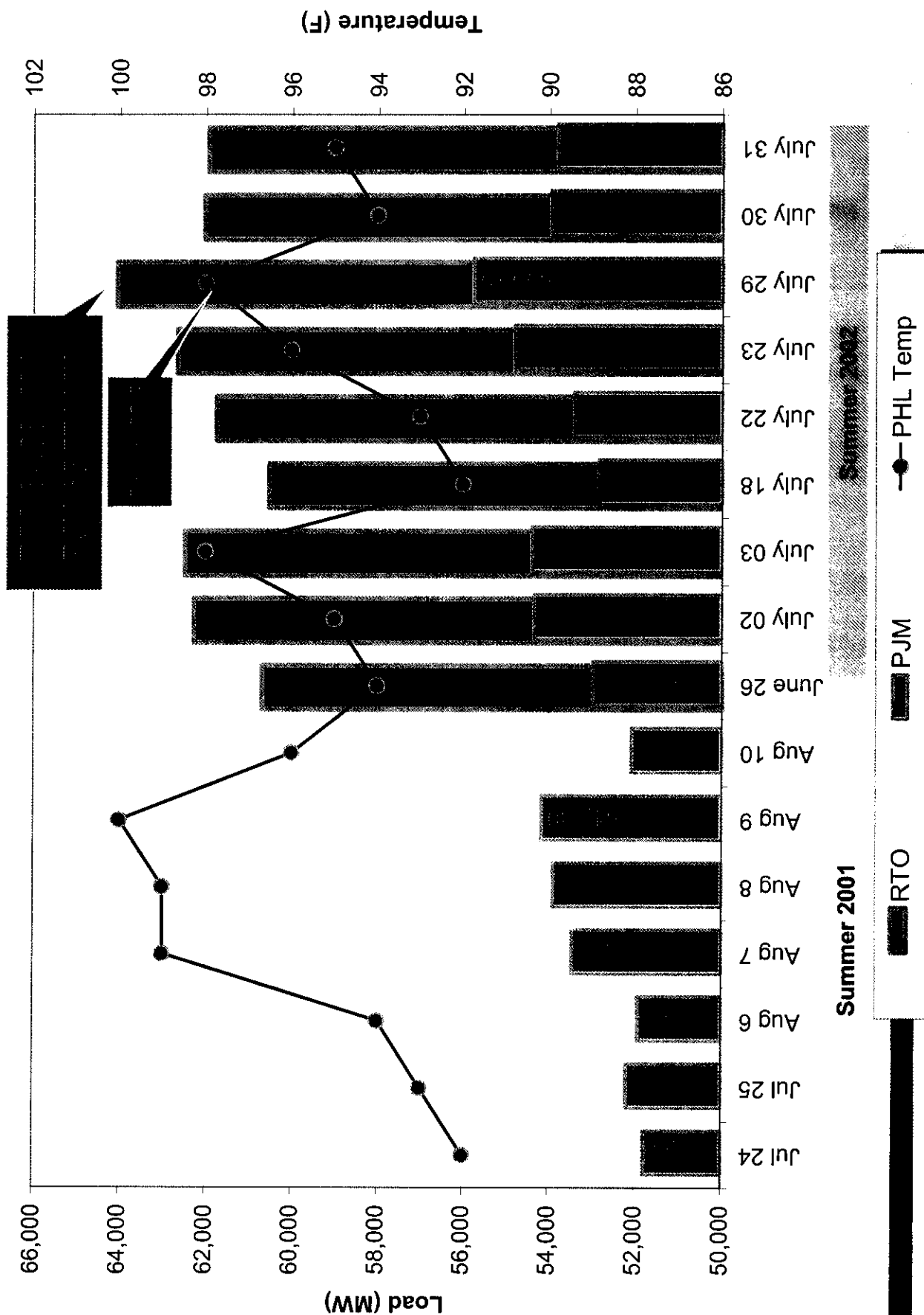
Summary



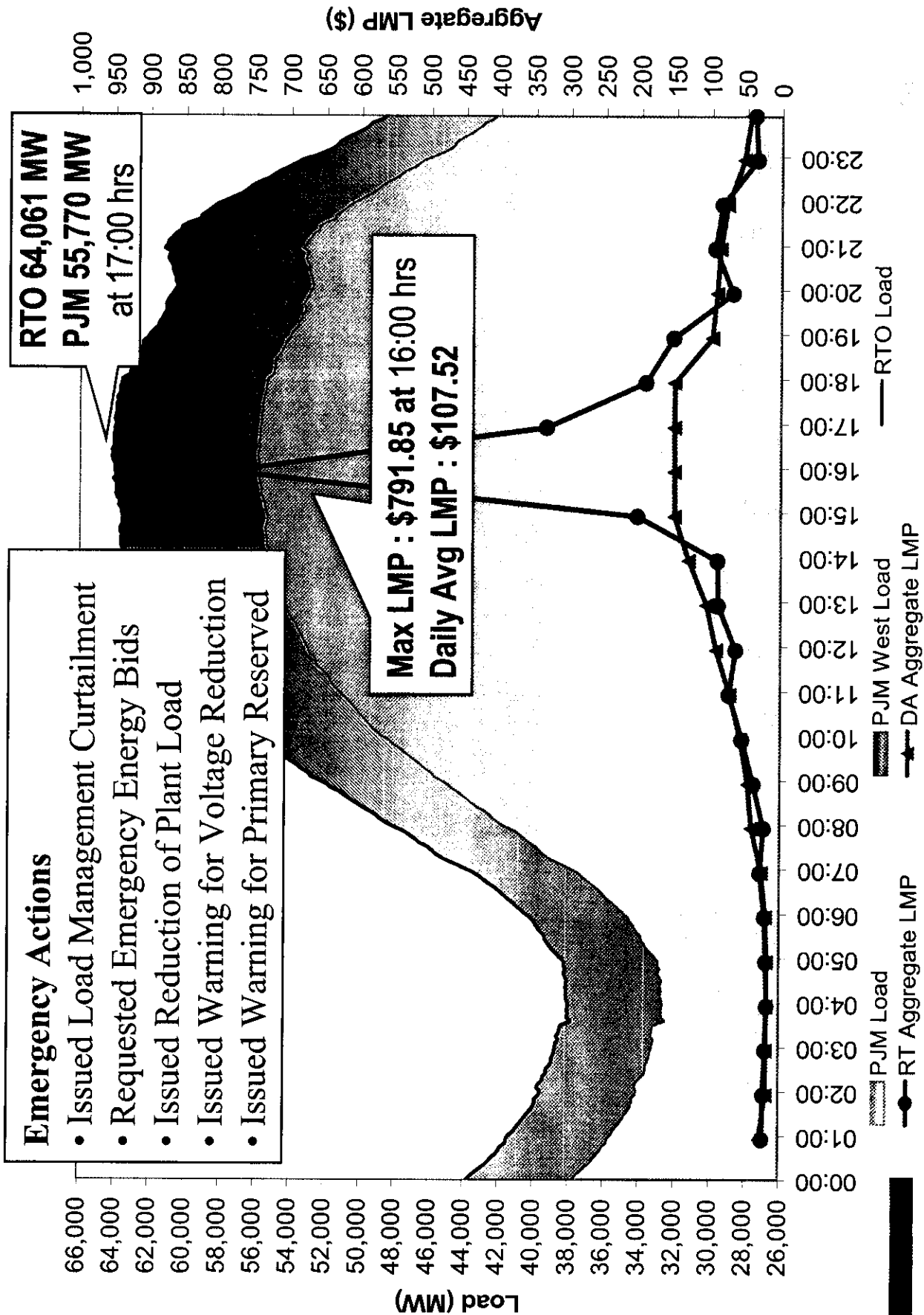
Summer 2002

(June 1st – July 31st 2002)

Load and Temperature Trend



Load and System Cost - July 29, 2002





Summer 2002 Emergency Procedures

Warnings Issued

- Primary Reserve Warning (2 Events)
- Voltage Reduction Warning (3 Events)

Actions Issued

- Requested Emergency Energy Bids (3 Events)
- Load Management Curtailment 1-4 (3 Events)
- Voluntary Load Reduction (1 Event 7/3/2002)
- Reduction of Non-Critical Plant Load (2 Events)

Summer 2002 System Voltage

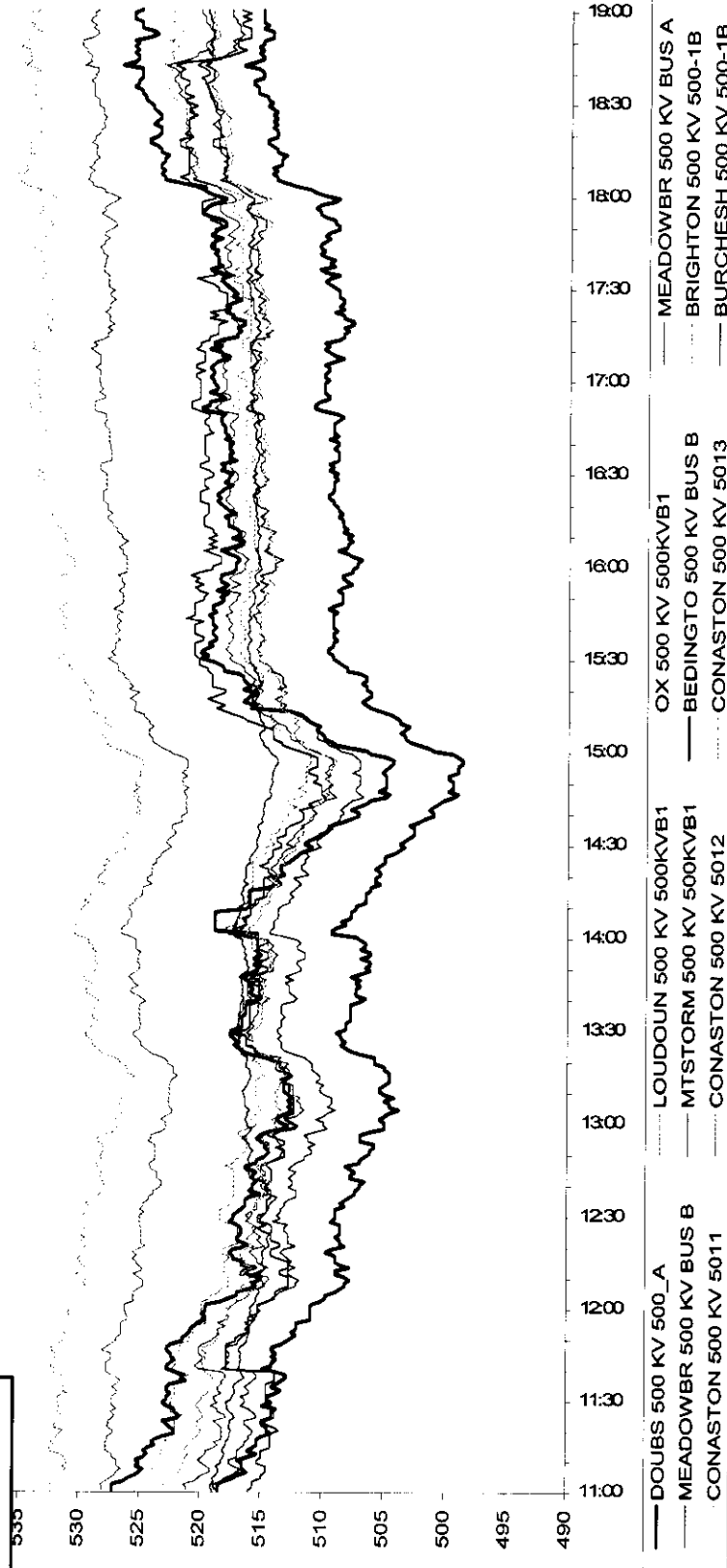
Reactive Support

- Issued 22 Heavy Load Voltage Schedules
- Requested nine (9) Maximum Var Support procedures in AP zone

500 KV Voltage Support

- Maintained the PJM Area 500KV Voltages within Operating Limits
- Experienced Low Voltages at AP Doubts Station on three occasions
- Research indicates related to Doubts - Mt.Storm impedance characteristics

7 / 9 / 2002



Reactive Transfers

Reactive Transfers

- Operated to Two Additional Transfer Interfaces located in AP:
 - Bedington-Black Oak - 500 KV path between Hatfield's Ferry and Doubs AP-South
 - 500 KV cut east of Mount Storm
- PJM experienced far fewer Western, Central and Eastern Transfer Off-Cost Operations vs last summer, thanks to knowledge gained from RTO merger
- PJM RTO also implemented a number of new Reactive interfaces, to aid in contingency control: PJM 500 KV Reactive, PJM West 500KV Reactive, RTO 500 KV Reactive PJM Voltage, PJM West Voltage, RTO Voltage

Transfers Off-Cost Operation Hours Jun-Jul 2002

• Eastern Transfers	19.2 Hrs
• Central Transfers	None
• Western Transfers	None
• Bedington-Black Oak	237.7 Hrs
• AP South	80.7 Hrs
• All Other Reactive Interfaces	59.9 Hrs

Transmission Operations

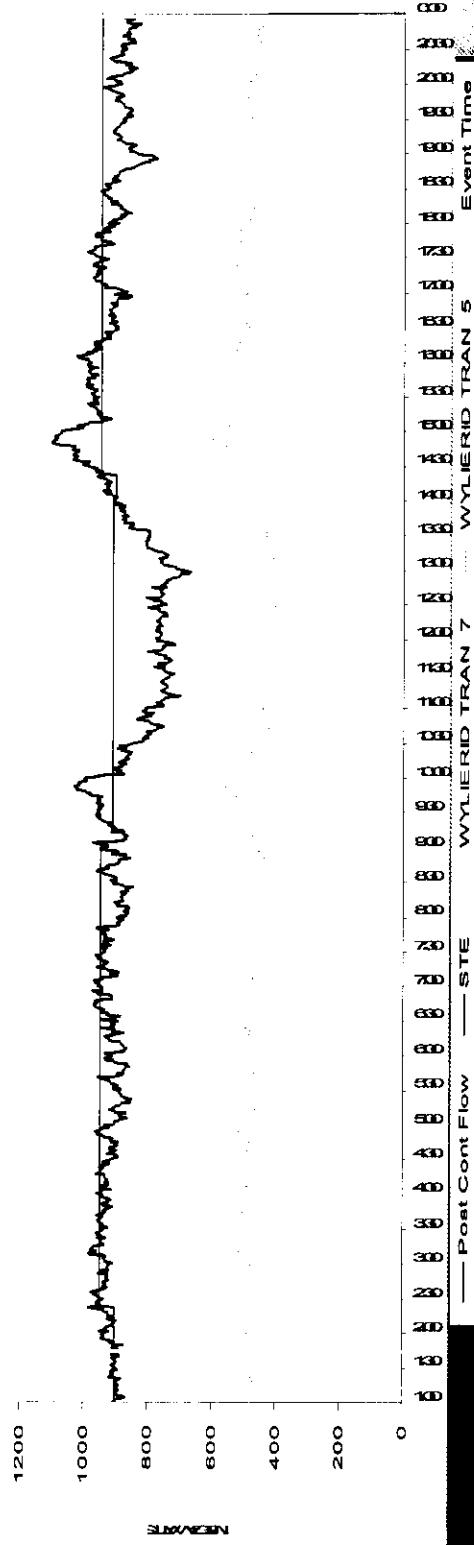
- Controlled for all Actual Line Overloads within NERC Standards
- Issued Three Voltage Reduction Warnings
- No System Wide Load Dump Warning were issued; all area specific

Manual Load Dump Warning

- Issued 1.6 Hours for Zones AP, PE, PS, DPL & JC
- Issued 496.3 Hours for Specific Areas - E.Towanda, Erie West, etc.

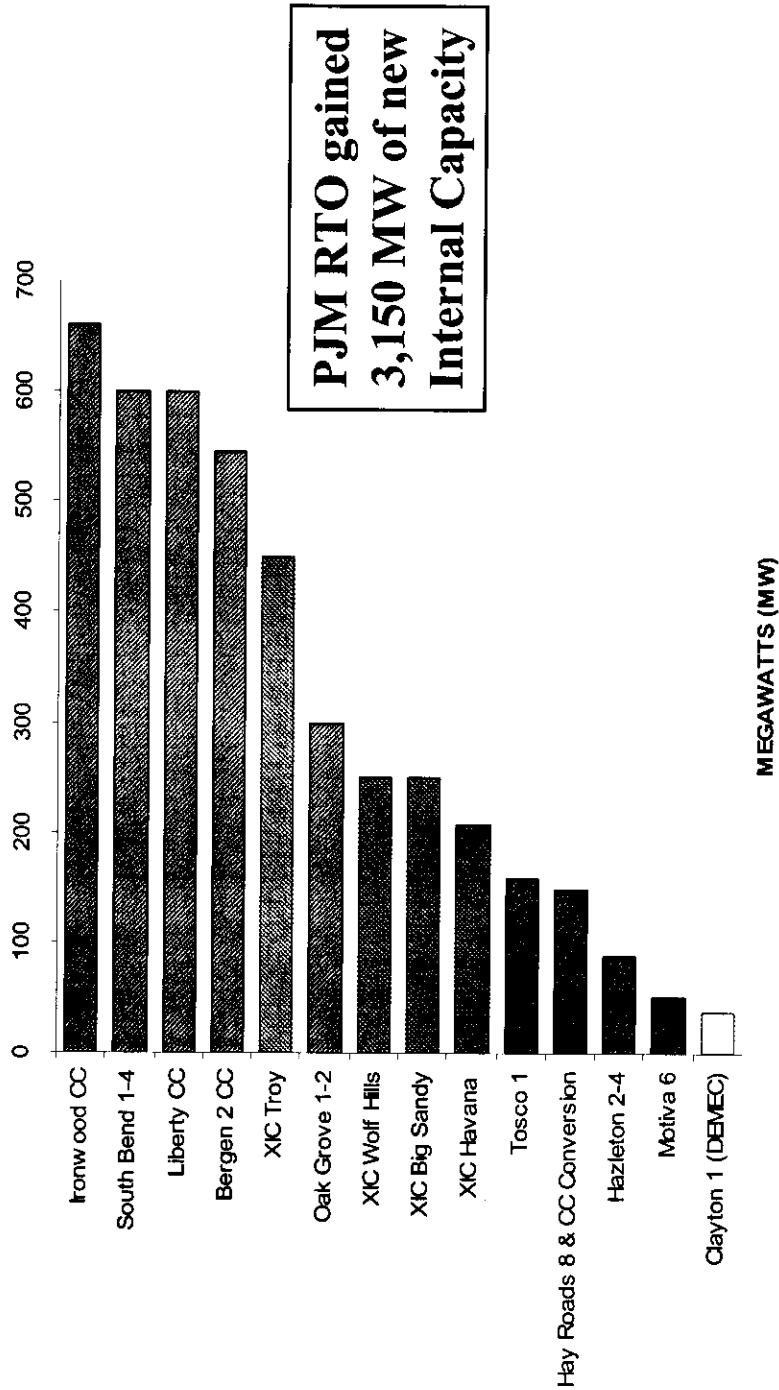
Transmission Loading Relief (TLR)

- Requested 337 Hrs for Wylie Ridge Transformers
- Requested 23 Hrs for all others: Doubs Transformers, Bedington-BlackOak, and Kammer Transformers



Real Time Operations

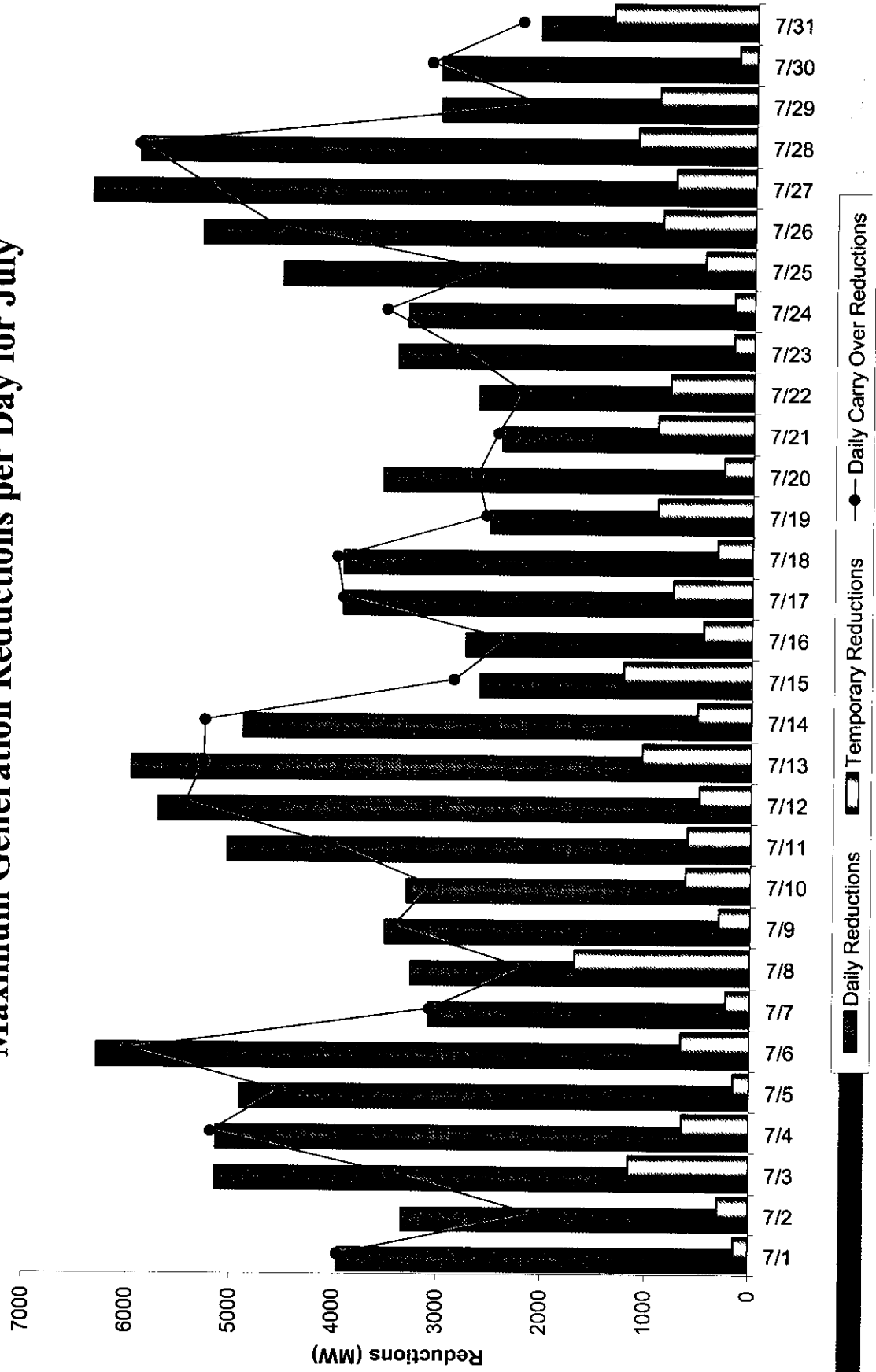
- Called 14 100% Spinning Events for Unit Loss, 3 for Low ACE, 6 for Transfers
June-July 2001: 7 for Unit Trips, 6 for Low ACE, 6 for Transfers
- PJM capitalized on a number of new additions to its fleet, as well as a new capacity class : Externally Installed Capacity [XIC]



- Hunterstown Combined Cycle, XIC Sammis, XIC Mansfield are not currently dispatchable. Clayton 1 (DEMEC) is currently in Testing phase.

Generation Operations

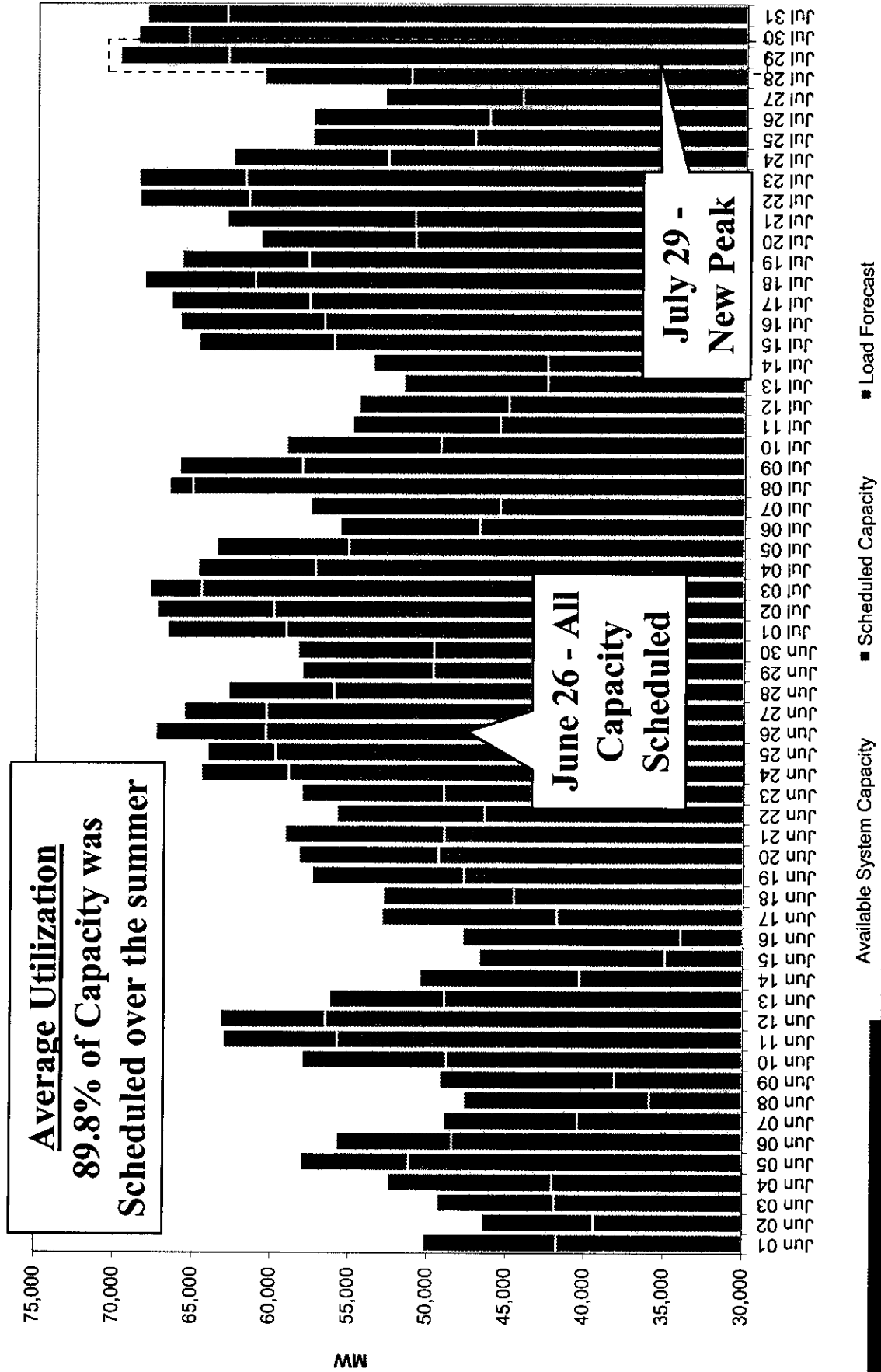
Maximum Generation Reductions per Day for July



* Temporary (< 12 Hours Duration), Daily (> 12) Reductions, and Reductions Carried over to the next day

Generation Operations

Calculated Available Capacity, Scheduled Energy and Load Forecast

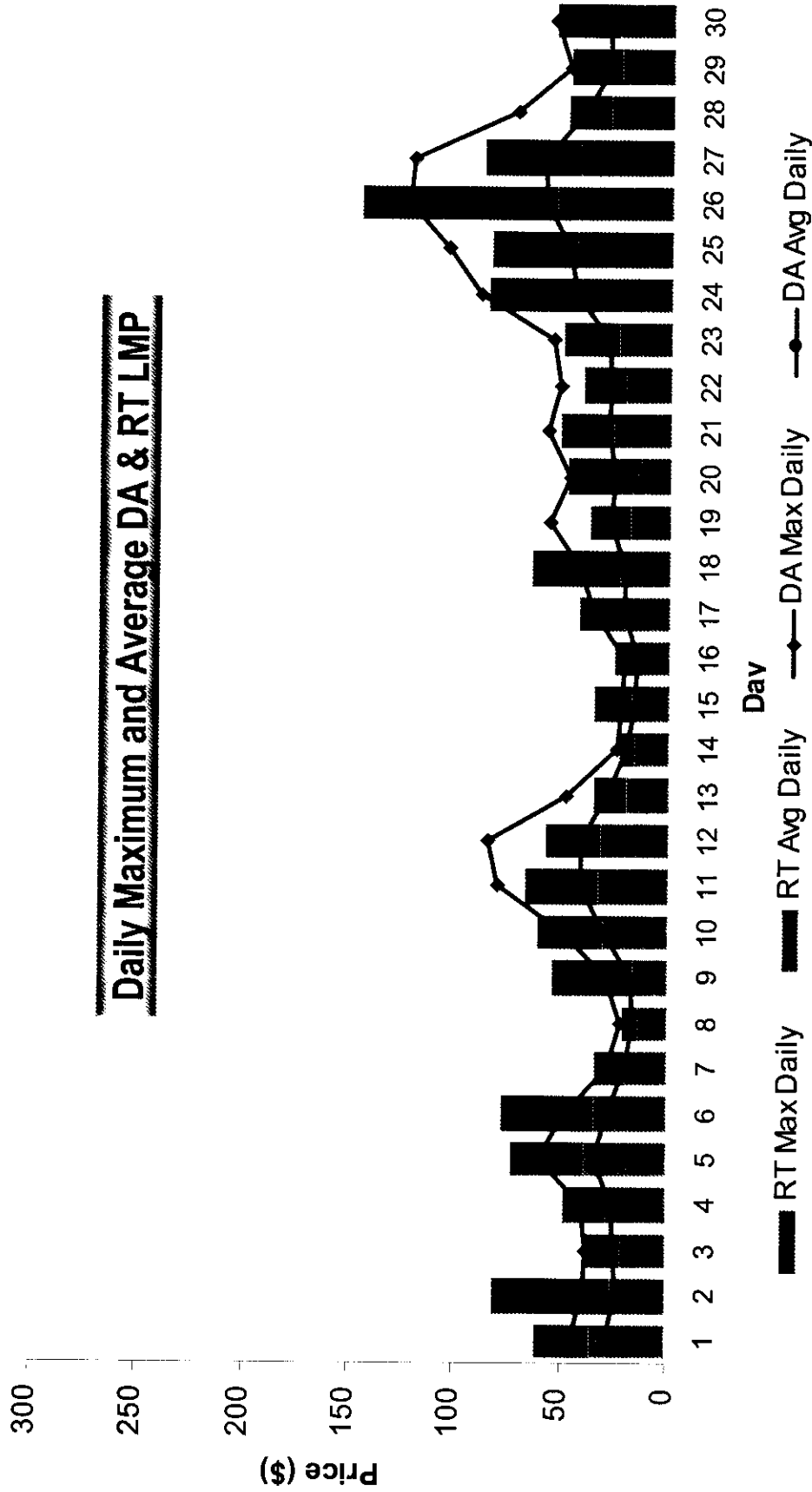


Energy Prices - June 2002

June Energy Prices

- Day Ahead: Maximum LMP was \$124 with an Average of \$30
- Real Time: Maximum LMP was \$147 with an Average of \$28

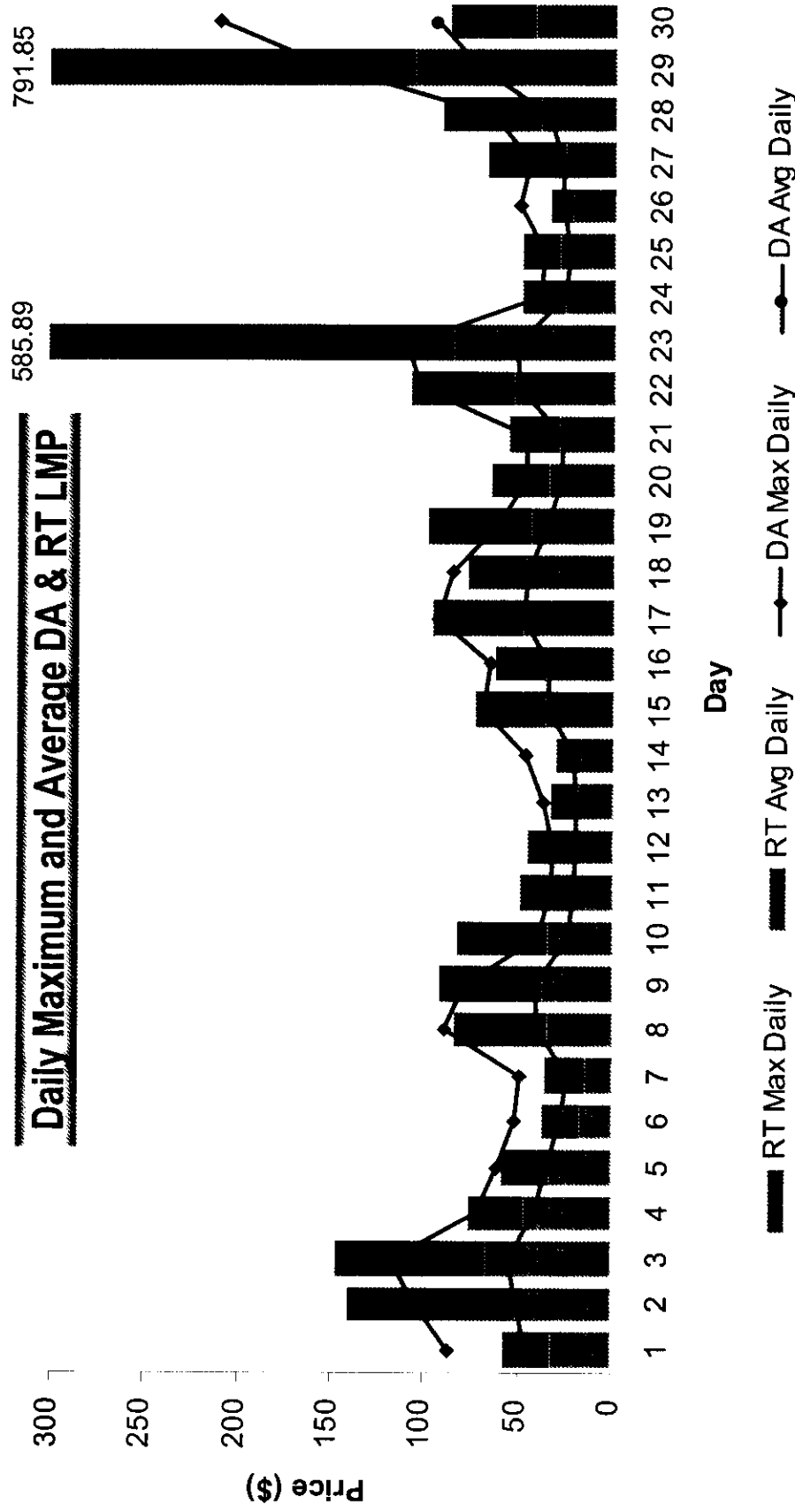
Daily Maximum and Average DA & RT LMP



Energy Prices - July 2002

July Energy Prices

- Day Ahead: Maximum LMP was \$212 with an Average of \$38
- Real Time: Maximum LMP was \$792 with an Average of \$39



LMP Pricing Summary

- June Day Ahead and Real Time Energy Prices were Below \$200 for All Hours. The month's High LMP was \$124 in the Day Ahead market and \$147 in Real Time markets.
- July Day Ahead and Real Time Energy Prices were Below \$200 for all but Four hours. The month's High was \$212 in the Day Ahead market and \$792 in Real Time markets.

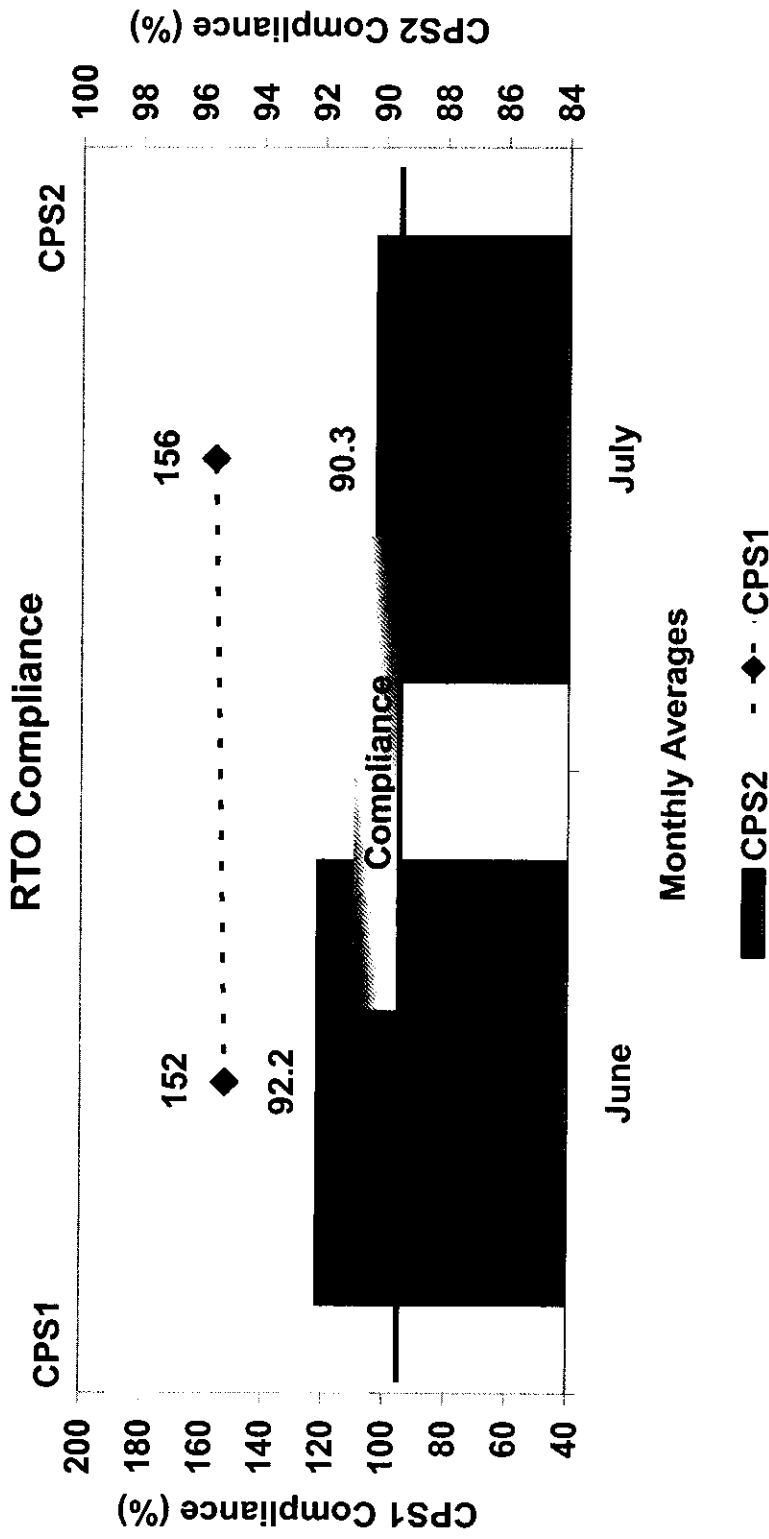


NERC Performance Standards

- PJM RTO met CPS 1 & 2 Standards
 - June: CPS1 = 152% CPS2 = 92.2%
 - July: CPS1 = 156% CPS2 = 90.3%

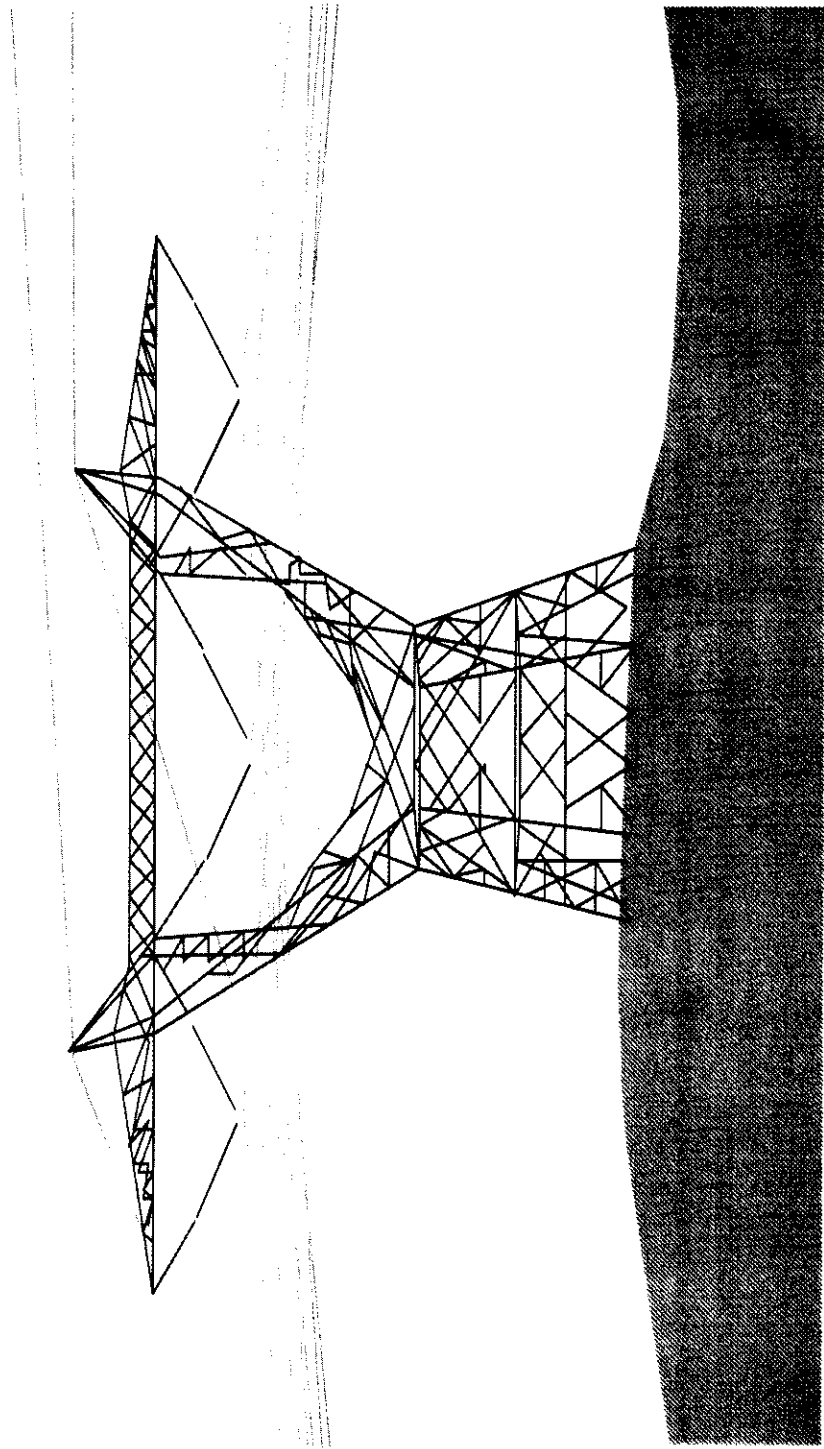
- Also met all DCS Recovery Criteria

NERC Control Performance Standards



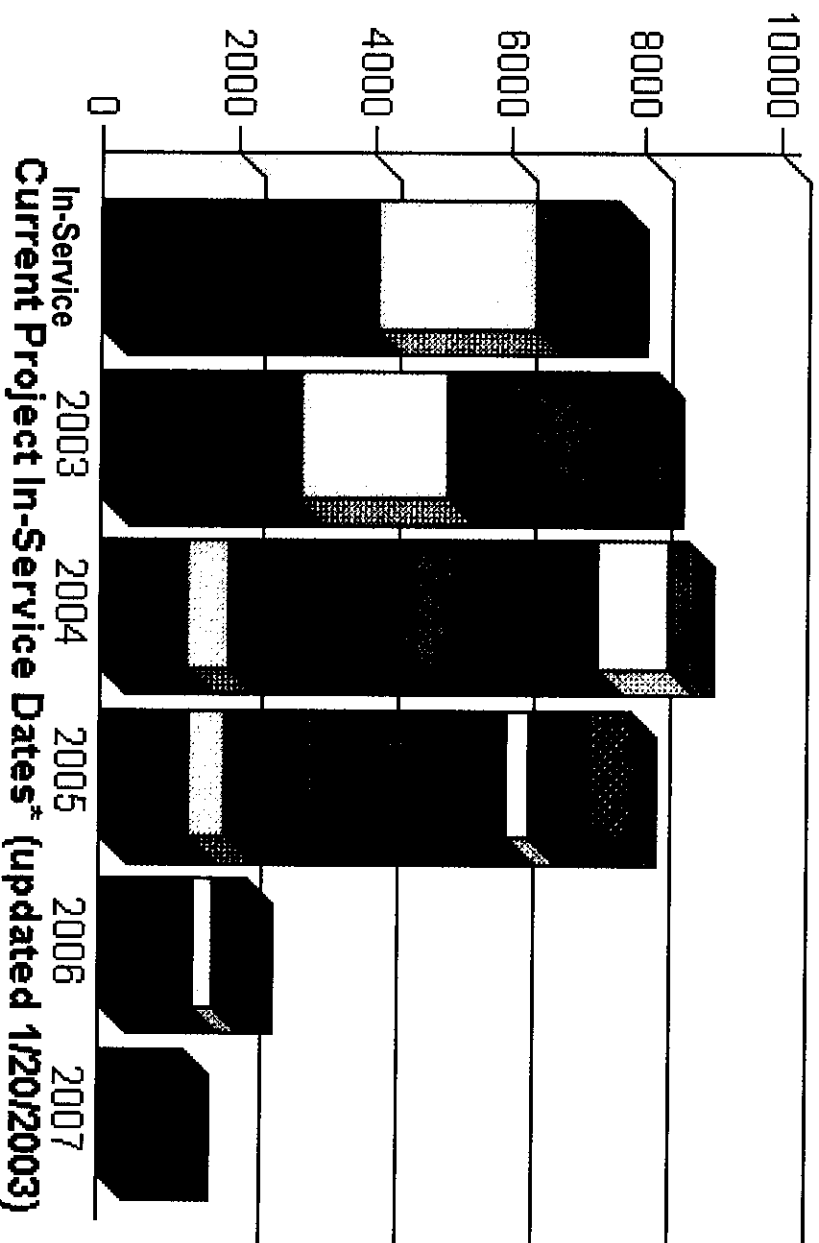
Summer Summary

- New PJM and RTO All-Time Peaks
 - Tuesday, July 2nd : 54,343 MW, RTO 62,290 MW
 - Wednesday, July 3rd : 54,404 MW, RTO 62,490 MW
 - Tuesday, July 23rd : 54,817 MW, RTO 62,660 MW
 - Monday, July 29th : 55,770 MW, RTO 64,061 MW
 - Previous Peak: August 9, 2001 - 54,176 MW
- **Set Seven of the Ten PJM all Time Peaks in the first two summer months of 2002...**
- PJM was able to meet demand with minimal Emergency Procedures and with a stable marketplace.



Queued Capacity By In-Service Date

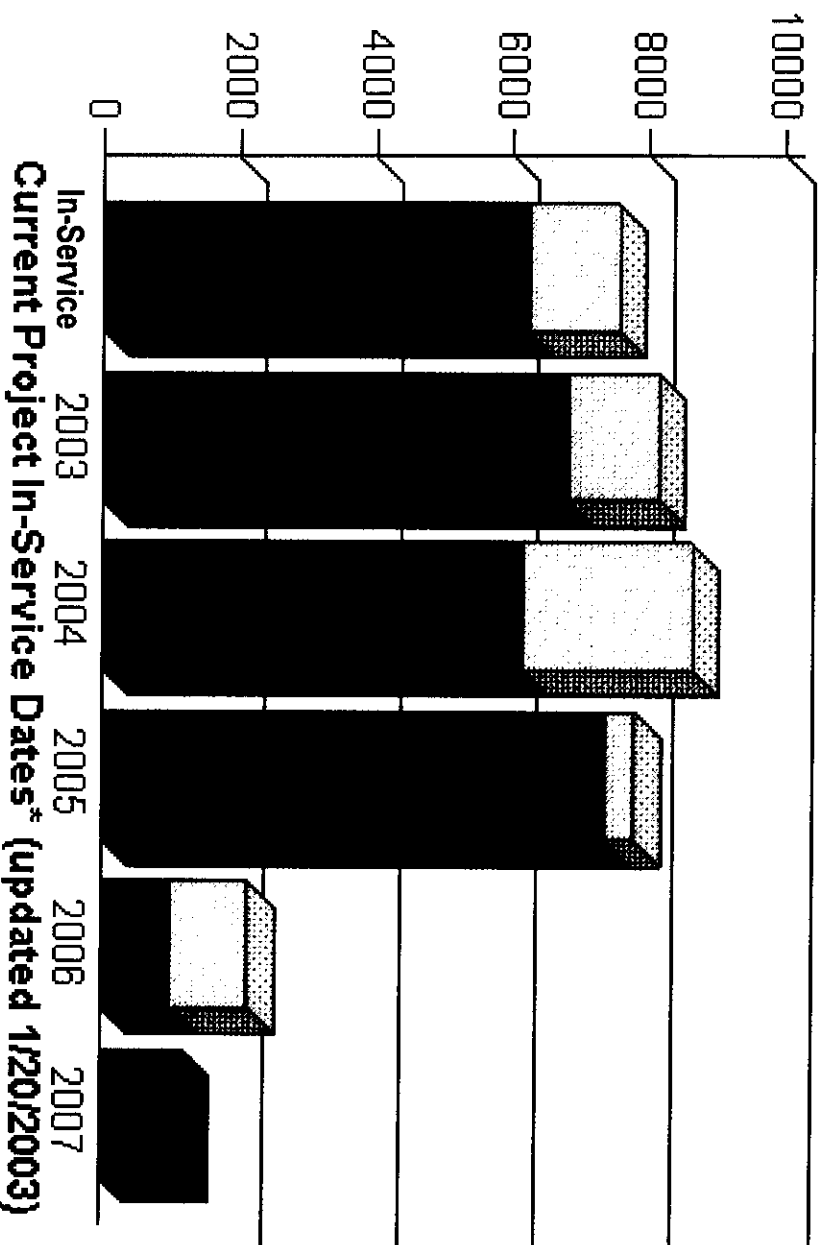
MW of New Capacity



* In-service dates of each project are provided by the developer. No judgement is made by PJM as to the likelihood of completion of any individual projects within the timeframes identified.

Queued Capacity By In-Service Date

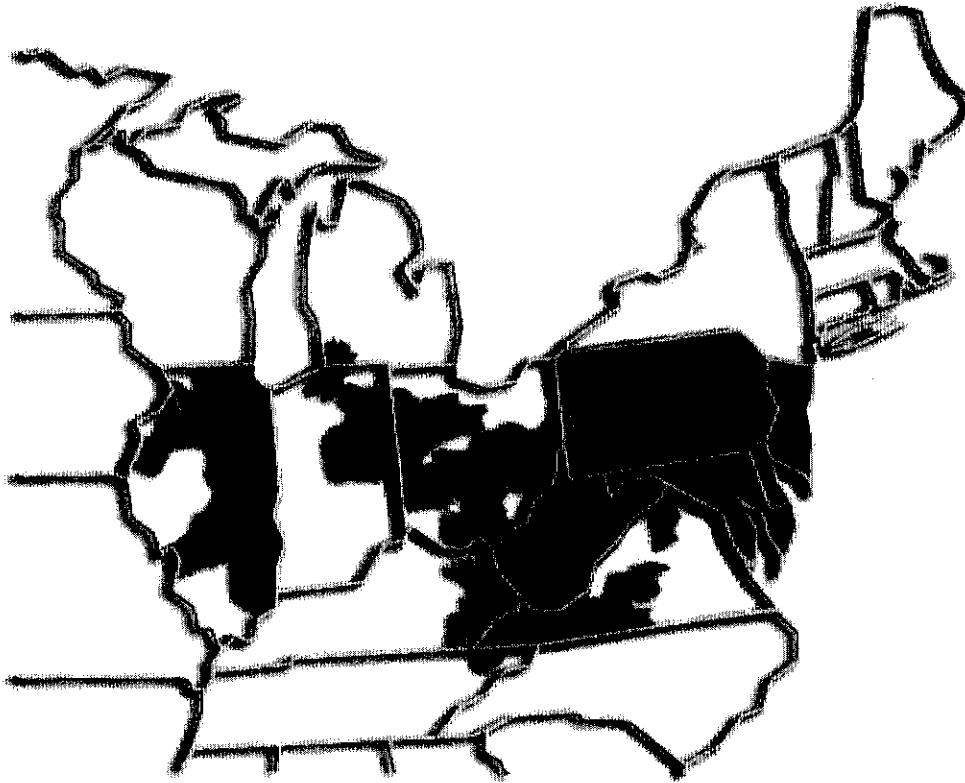
MW of New Capacity



* In-service dates of each project are provided by the developer. No judgement is made by PJM as to the likelihood of completion of any individual projects within the timeframes identified.

PJM RTO

Reliability Plan



Administrative Notes: For the purposes of this document the terms *Security Coordinator (SC)*, *Reliability Authority (RA)*, and *Reliability Coordinator (RC)* are synonymous. The PJM RTO's Reliability Coordinator operations will be addressed within this "Reliability Plan." Additionally the term Groveport is synonymous with the current ECAR-MET office and Lombard is synonymous with the current MAIN RC office

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I. Implementation Strategy Summary

PJM is on the verge of extending its operational area by expanding both to the West and South. Western expansion will include the incorporation of Duquesne, American Electric Power (AEP), Dayton Power and Light (DP&L), Commonwealth Edison Co. (ComEd), and Illinois Power (IP). Southern expansion will include the incorporation of Dominion. The intent of this expansion is to provide greater operational flexibility across a single market and be in compliance with recent FERC Orders.

PJM is committed to making these extensions of its Reliability Coordinator operations seamless to the reliability of the Eastern Interconnection.

PJM will execute this expansion utilizing a phased implementation strategy. The following section is an overview of the respective phases; however, this **Reliability Plan will only address RC operations necessitated by Phase 1 and 2.**

PHASE 1 – Incorporation of Duquesne and selected First Energy Generation into PJM market and Reliability Coordinator (RC) Operations. This phase may occur on or about November 1st, 2002. This phase is contingent on the outcome of various decisions. The impact of this change in control area and RC operations will be similar to the impact experienced by the incorporation of Allegheny Power into PJM/PJM West.

PHASE 2 – Implementing an expanded RC Zone across all of the future PJM companies (AEP, DP&L, ComEd, IP). This phase will include leveraging both GROVEPORT and MAIN offices as Reliability Monitoring Zones with PJM acting as the primary RC for the entire zone. Phase 2 will utilize current NERC procedures for tagging of schedules within the Transmission Operators' (TO) respective control areas and the primary use of NERC TLR for congestion management beyond the current PJM/PJM West zone. Because this phase is primarily an adjustment of ultimate responsibility and not procedures this phase will have minimal impact on operations throughout the Eastern Interconnection. This Phase will begin on or about December 1st, 2002 and conclude on or about May 1st, 2003.

PHASE 3 – Is the possibility of PJM assuming the RC function for the VACAR region. This Phase should have no impact on current NERC or regional practices and procedures. The only difference in operations is that another organization will be providing these same RC services. This phase may occur in the first quarter of 2002.

PHASE 4 – This phase includes the incorporation of AEP and DP&L under the PJM single market design. As such, this phase will conclude the need for GROVEPORT to act as the RC for this portion of the PJM zone. These responsibilities shift fully under PJM. Under a single market, all former AEP and DP&L schedules will sink into a single RTO zone. Therefore in this phase, PJM will operate with only two Reliability Monitoring Zones. These zones will include the expanded PJM RC zone and MAIN monitoring zone (a third zone will be required if PJM assumes VACAR duties). The impact of this Phase on both the MISO and other parties will be addressed in subsequent Reliability Plans. These subsequent plans will include the strategies that MISO and PJM have developed to mitigate reliability seams issues between operating entities. Though timelines are currently being created, NERC and the regions should expect our updated Reliability Plan no later than February 1st, 2003. This Phase will begin on or about April 1st 2003 and conclude on or about December 1st 2003.

PHASE 5 – This phase includes the incorporation of Dominion under the PJM single market and RC operations. This phase's future Reliability Plan will include an extension of strategies employed in Phase 3 to mitigate reliability seams issues. Reliability Plans will be available by August 1st, 2003. This Phase will occur on or about October 1st, 2003.

PHASE 6 – This Phase includes the incorporation of IP and ComEd into the PJM single market. With the implementation of this Phase, the MAIN office will no longer need to act as a monitoring zone for the portion of the PJM RC zone that includes IP and ComEd. Because of the higher degree of geographic integration with MISO, the importance of having fully integrated mitigating strategies is increased. Reliability Plans will be available by October 1st, 2003. This Phase will begin on or about December 1st, 2003 and will conclude with the integration of PJM and MISO under a single market.

PHASE 7 – This Phase will cover the melding of PJM and MISO's operations and markets under the single market design (SMD).

PJM's RC responsibilities will incrementally span the entire MAAC region, and large portions of the ECAR and MAIN regions. This inter-regional RC will be aligned with the borders and responsibilities of the PJM RTO. For the purposes of avoiding confusion this document's references to the RTO RC include the complete inter-regional PJM zones, for Phases 1 and 2.

II. Introduction to the PJM RTO

The PJM/PJM West RTO is currently comprised of ten utilities, whose transmission systems span the Mid-Atlantic region of New Jersey, most of Pennsylvania, Delaware, Maryland, West Virginia, Ohio, Virginia, and the District of Columbia. With the inclusion of AEP, DP&L, ComEd, and IP into its Reliability Area, PJM will span its former states and large portions of Indiana, Illinois, and Wisconsin states. These geographic extensions are also extensions of operations within the ECAR and MAIN NERC regions.

The RTO RC will be responsible for maintaining the reliability of the integrated transmission system over which it has been given authority by its Transmission Owners. As the Reliability Coordinator the **RTO RC's** responsibilities will include:

- ❑ Transmission system security monitoring and analysis
- ❑ Coordination with other Reliability Coordinators
- ❑ Coordination with and control of the control areas within the PJM RTO
- ❑ Initiation of an inter-control area constrained unit dispatch to relieve congestion
- ❑ Unit scheduling
- ❑ Response to emergency situations
- ❑ Implement reliability measures such as the NERC TLR.
- ❑ Initiate reconfiguration measures to ensure transmission congestion is mitigated.
- ❑ Approval of the scheduling of RTO transmission facility and generation maintenance
- ❑ And other actions that are required to maintain system reliability.

RTO RC reliability procedures and policies will be consistent with those of NERC. The **RTO RC** will operate in multiple NERC Regions and will recognize each Region's policies and standards. Where there are conflicts in the Regional Policies and Standards, the **RTO RC** will work with the Regions and members on resolving those conflicts.

III. PJM RTO Reliability Plan

A. Compliance with NERC Criteria for Reliability Coordinators (NERC Operating Manual, Policy 9)

1. **Responsibilities.** The **RTO RC** has a clear set of responsibilities and procedures for when, where and how to take action per its tariff and coordination agreements.
2. **Facility Status.** The **RTO RC** has the knowledge of current and planned critical facility status through its real time EMS, Reliability Monitoring Zone applications, and coordination between these Monitoring Zones and their Local Control Centers. PJM's eDART outage management system provides information on planned Generation and Transmission system outages.
3. **Authority to Act.** The **RTO RC** has the authority to act and to direct actions to be taken by other Operating Authorities within the Reliability Area per its tariff and implementation agreements.
4. **Serve Interests of the Reliability Area and the Interconnection.** The **RTO RC** will act independently in the interests of reliability of the overall Reliability Area/Interconnection before any other entity as an RTO.
5. **Staff and Facilities.** The **RTO RC** has adequate staff and facilities.
 - 5.1. **Continuous Staffing.** The **RTO RC** is staffed with appropriately trained, NERC Certified System Operators, 24 hours a day, 7 days a week at each of its three Reliability Monitoring Zones RC Desks (PJM, Lombard, Groveport).
 - 5.2. **Adequate Facilities.** The **RTO RC** has the redundant facilities needed to perform reliability coordination responsibilities, including
 - Appropriate Communications (voice and data links)
 - **RTO RC** employs a private communication network with its members for voice, message, and data exchange.
 - **RTO RC** employs redundant links to the NERC Interregional Security Network (ISN), and supplies data to the ISN on behalf of its members, and obtains information from the ISN.
 - Timely information
 - Detailed monitoring and analysis capability of the Reliability Area and sufficient monitoring capability of the surrounding Security Areas to ensure potential security violations are identified.
 - Comprehensive Understanding of their Reliability Area and interaction with neighboring Reliability Areas.
 - Back-up facilities

5.3 Continuous Monitoring of Reliability Area. The **RTO RC** ensures that its Reliability Area of responsibility is continuously and adequately monitored. PJM has real time monitoring and analysis transmission facilities both from its internal EMS applications and from current Reliability Monitoring Zone applications (GROVEPORT, MAIN). Additionally, Transmission Owners continue to monitor and analyze their transmission systems and notify PJM's respective Reliability Monitoring Zones in the event that the RTO RC has not already taken action to alleviate a real time or contingency condition. The **RTO RC** has back-up facilities to ensure continuous monitoring.

- 6. Independence.** The **RTO RC** is independent of the merchant function. The **RTO RC** will not pass on information to any wholesale merchant function (either internal or external) that is not made available simultaneously to all such wholesale merchant functions.
- 7. Standards of Conduct.** The **RTO RC** will sign the NERC Reliability Coordinator Standards of Conduct [Section C. "Reliability Coordinator Standards of Conduct."].

B. Function of Reliability Coordinators

The RTO RC is responsible for the following functions:

1. The RTO RC will monitor the parameters that may have significant impacts throughout the PJM RELIABILITY AREA and with neighboring RELIABILITY AREAS with respect to:

1.1. Pending interchange schedules to identify potential parallel flow impacts. As constrained areas approach reliability limits, the RTO RC will work with PJM's Reliability Monitoring Zones as well as the CONTROL AREA operators to evaluate and assess any system reconfiguration and redispatch options that could relieve the impact of parallel flows. In the event that all effective non-cost and redispatch options (only within the current PJM Zone) are exhausted the RTO RC will assess INTERCHANGE SCHEDULES that would have an adverse impact on the CONSTRAINT. If CONSTRAINTS cannot be avoided through proactive intervention (reconfigure and redispatch), the RTO RC may initiate the appropriate loading relief procedure. NOTE: During Phase 2 the redispatch option will only exist within the current PJM/PJM West zone.

1.1.1. Confidentiality. At all times, the RTO RC shall respect the confidential nature of curtailment information when communicating the necessary INTERCHANGE TRANSACTION reductions to the CONTROL AREA operators throughout all of the PJM Reliability Zone. As PJM expands its operations/market across additional TO's the ability to protect the confidential nature of data will increase. This increase is a result of PJM acting as both the RTO RC and as the Interchange Authority, PJM's ability to maintain this confidentiality is enhanced because the decision to act and the actual curtailment(s) is/will be made in the same Operations Center.

1.2. Availability/shortage of operating reserves needed to maintain reliability. Having the generation scheduling responsibilities for its zone of operations, the RTO RC will ensure that the required amount of operating reserves are provided/carried by the Control Areas under PJM's RC Zone. In Phase 1 and 2, reserves will be maintained by all parties under current reserve sharing and obligation agreements. If necessary, the RTO RC will arrange for assistance from neighboring areas (CONTROL AREAS, REGIONS, etc.). The RTO RC will issue ENERGY EMERGENCY ALERTS as appropriate.

1.3. Actual flows versus limits at key facilities (particularly inter-CONTROL AREA, inter-REGIONAL and inter-RELIABILITY AREA

interfaces) The **RTO RC** will identify the cause of the **CONSTRAINT** and coordinate loading relief by requesting appropriate corrective action according to previously established procedures.

1.4. Time error correction and SMD notification. The **RTO RC** will communicate start and end times for time error corrections to the **CONTROL AREAS** within its **RELIABILITY AREA**. The **RTO RC** will ensure all **Control AREAS** and regional reliability councils as required are aware of Solar-Magnetic Disturbance (SMD) forecast information and assist as needed in the development of any required response plans.

1.5. Reliability issues of other Regions. The **RTO RC** and its Reliability Monitoring Zones (GROVEPORT, MAIN) will participate in NERC Hotline discussions, assist in the assessment of security of the Regions and the overall interconnected system, and coordinate actions in anticipated or actual emergency situations. The **RTO RC** will disseminate information within its **RELIABILITY AREA**.

1.6. System frequency and resolution of significant frequency errors, deviations, and real-time trends. The **RTO RC** will monitor system frequency and work with its **CONTROL AREAS** and neighboring **RELIABILITY COORDINATORS** to identify the source of frequency deviations and real-time trends and aid in the establishment of corrective actions.

1.7. Sharing with other RELIABILITY COORDINATORS any information regarding potential, expected, or actual critical operating conditions that could negatively impact other RELIABILITY AREAS. The **RTO RC** will coordinate with other **RELIABILITY COORDINATORS** and **CONTROL AREAS** as needed to develop appropriate plans to mitigate negative impacts of potential, expected, or actual critical operating conditions. This would include coordination of pending generation and transmission maintenance outages in both the operating and the planning timeframes. (What about the exchange of data?)

1.8. Availability/shortage of Interconnected Operations Services required (in applicable RELIABILITY Areas). As necessary, the **RTO RC** will arrange for assistance from neighboring areas (Control Areas, Regions, etc.).

1.9. Individual CONTROL AREA or RELIABILITY AREA ACE (in applicable RELIABILITY AREAS). The **RTO RC** will identify sources of large ACE deviations that may be contributing to frequency, time error, or inadvertent problems and will coordinate the corrective action with its Reliability

Monitoring Zones (GROVEPORT, MAIN) and CONTROL AREAS. At all times the RTO RC will monitor the ACE of all of its control areas. If a frequency, time error, or inadvertent problem occurs outside of the RELIABILITY AREA, the **RTO RC** will discuss this condition, on the NERC Hotline, with other RELIABILITY COORDINATORS.

1.10. Use of Special Protection Systems (in applicable RELIABILITY AREAS). Whenever a Special Protection System that may have an inter-CONTROL AREA or inter-RELIABILITY AREA impact is armed, the **RTO RC** shall be aware of the impact of the operation on inter-Area flows.

1.11. Control and restoration of islanded areas. The **RTO RC** will assist CONTROL AREA operators in controlling islanding. The RELIABILITY COORDINATOR will assist the CONTROL AREA operators in re-establishing normal system configuration as requested and coordinate communications as required. When applicable the RTO RC will suggest and assist the Control Areas when linking the islands and the ties between the RTO members.

2. The RTO RC staff shall adhere to the NERC data confidentiality agreement at the time of employment and will receive annual training on the requirements to adhere to the PJM RTO code of conduct. The RTO RC will ensure that its operations comply with this confidentiality agreement through training and audits.

3. The RTO RC has assumed the responsibility for the safe & reliable operation of the bulk interconnected transmission system in accordance with NERC, Regional, coordinated agreements, and sub-Regional practices per its tariff. Though PJM has two Reliability Monitoring Zones (GROVEPORT/MAIN), as the RTO RC PJM has this critical responsibility throughout the entire RTO footprint.

4. The RTO RC has determined and will maintain the data requirements to support the reliability coordination function and coordinate for the provision of such data.

5. The RTO RC shall conduct security assessment and monitoring programs to assess contingency situations. Using advanced applications the RTO RC assesses in both real time and in the operations planning horizon security analysis results (line loading and voltage drops) to identify any problems within the **RTO RC** zone. Thermal transmission limits are monitored continuously through PJM's Transmission Monitoring program. Reactive constraints are addressed by operating to limits computed for five composite reactive interfaces. These interfaces' limits, updated every few minutes, are monitored continuously on a first contingency basis. The **RTO RC** ensures that

CONTROL AREA, RELIABILITY AREA, and regional boundaries are sufficiently modeled to capture problems crossing such boundaries. During the initial phases of PJM RC functions (Phases 1 and 2), PJM will utilize current applications used by MAIN and GROVEPORT.

6. The RTO RC will ensure each CONTROL AREA has a restoration plan in accordance with NERC and Regional requirements. During system restoration, the **RTO RC** shall monitor restoration progress and take a leadership role in coordinating needed assistance. The **RTO RC** will serve as the primary contact for disseminating information regarding restoration to neighboring RELIABILITY COORDINATORS and CONTROL AREAS not immediately involved in restoration. The RTO RC will also be involved in semi-annual regional restoration drills to ensure these plans and procedures remain flexible and responsive to handling a restoration emergency. In order to enhance restoration operations between PJM and MISO, both RTO's will conduct annual coordinated restoration drills. These drills will stress cooperation and communication so that both RTO's are positioned to better assist the other in a real restoration.

7. The RTO RC will work with member Control Areas to ensure that applicable voltage collapse studies are run. As the **RTO SC**, PJM will perform voltage collapse studies every few minutes. As required, PJM will immediately respond to problems identified by these studies. The Long and Short Range Planning Departments within the RC Reliability Area will perform studies to include and disclose voltage collapse problem areas. Analysis will be performed as required and based upon the results of this analysis.

8. The RTO RC shall provide other coordination services as appropriate and as **requested** by the CONTROL AREAS within his RELIABILITY AREA and neighboring RELIABILITY COORDINATORS. The **RTO RC** shall confirm study results and determine the effects within its own and adjacent RELIABILITY AREAS. This action includes discussing options to mitigate system constraints.

IV. Reliability Coordinator Analysis Procedures

A. Next Day Operations Planning Process

When disseminating system analysis information, the **RTO RC** will comply with the provisions of NERC's "Confidentiality Agreement for Electric System Security." [NERC Operating Manual Appendix 4B]

Requirements

1. Perform security analysis. The **RTO RC** performs next-day security analyses for all of the CONTROL AREAS in its RELIABILITY AREA to assure that the bulk power system can be operated in anticipated normal and contingency conditions.

1.1. Information sharing. Each **CONTROL AREA** in the PJM / PJM West RELIABILITY AREA shall provide information required for system studies, such as critical facility status, load, generation and operating reserve projections. Transmission owners shall provide information required for system studies, such as planned facility status, outage information, abnormal operating conditions, local security measures and voltage schedules. Generator owners provide planned generator status and dispatch. This information shall be available to the **RTO RC** by 1200 Central Standard Time the prior day.

1.2. System Studies. The **RTO RC** conducts studies to identify potential interface and other OPERATING SECURITY LIMIT violations, including overloaded transmission lines and transformers, voltage and stability limits, etc.

1.3. Unit Scheduling. Within the current PJM footprint, PJM uses the As the results of the operations planning analysis, the **RTO RC** schedules generating capacity using a process that includes a distribution based approach that accounts for facility impacts on system security. This scheduling process is updated for changes in system conditions and run as required 24 hours a day. The scheduling process uses PJM and company supplied generation schedules, with regional transaction schedules and regional hourly loads.

2. Study Results. The **RTO RC** shares the results of these system studies, when conditions warrant, or upon request, with other RELIABILITY COORDINATORS and CONTROL AREAS within their RELIABILITY AREA. Study results are available no later than 1500 Central Standard Time. If the results of these studies indicate potential RELIABILITY problems, the **RTO RC** issues the appropriate alerts via the RELIABILITY Coordinator Information System (RCIS.)

3. Conference calls. Any time that conditions warrant, a conference call or other appropriate communications is initiated by the **RTO RC** to address whatever problems are revealed by the security analyses. The **RTO RC** will also participate in any situationally dependent regional reliability council conference calls. If either the ECAR or MAIN office needs to schedule a conference call they will either contact the PJM Shift Supervisor via the RCIS or by direct phone call (number excluded for security reasons).

4. Special operating procedures. The **RTO RC** has developed and implemented the potential operating procedures that may be required to reconfigure the transmission system, redispatching generation, and to reduce or curtail INTERCHANGE TRANSACTIONS to maintain transmission loading within acceptable limits. [See NERC Operating Manual Appendix C1, Subsection E, “Principles for Mitigating Constraints On and Off the Contract Path.”]

B. Current Day Operations – Energy

Requirements

1. CONTROL AREA generation resource availability analysis. The **RTO RC** analyzes generation resource availability and reserve levels for the CONTROL AREAS, RESERVE-SHARING GROUPS, and LOAD-SERVING ENTITIES in his RELIABILITY AREA to determine any actual or potential energy deficiencies.

2. Authority to provide emergency assistance. The **RTO RC** has the authority to take or direct whatever action is needed to mitigate an energy emergency within its RELIABILITY AREA.

3. Notification. When the **RTO RC** is experiencing a potential or actual energy emergency within any CONTROL AREA, RESERVE-SHARING GROUP, or LOAD-SERVING ENTITY within its RELIABILITY AREA the **RTO RC** may initiate an ENERGY EMERGENCY ALERT as detailed in the **NERC Operating Manual Appendix 9B, Subsection A – “Energy Emergency Alert Levels.”**

4. Interconnection FREQUENCY ERROR. When the **RTO RC** notices an INTERCONNECTION FREQUENCY ERROR in excess of 0.03 Hz (Eastern Interconnection) for more than 20 minutes the **RTO RC** shall initiate a RELIABILITY COORDINATOR Hotline conference call, or notification via the RCIS, to determine the CONTROL AREA (S) with the energy emergency or control problem.

C. Current Day Operations – Transmission

Requirements

1. Interchange Transaction information. The RTO RC shall ensure that information on all INTERCHANGE TRANSACTIONS is available to all RELIABILITY COORDINATORS in the INTERCONNECTION.

1.1. Interchange Distribution Calculator. All Interchange Transactions whose SOURCE CONTROL AREA or SINK CONTROL AREA, or both, are in the EASTERN INTERCONNECTION must be entered into the Interchange Distribution Calculator (IDC). [See NERC Operating Manual Appendix 3A2, “Tagging Across Control Area Boundaries”]

1.2. Responsibility. The RTO RC for SINK CONTROL AREAS within its reliability area shall periodically audit the IDC to ensure that the INTERCHANGE TRANSACTION tags have been entered into the INTERCHANGE DISTRIBUTION CALCULATOR. The RTO RC will conduct random audits to ensure compliance from each of its Reliability Monitoring Zones (PJM, GROVEPORT, MAIN).

2. Notify RELIABILITY COORDINATORS of potential problems. When the RTO RC foresees a transmission problem within its RELIABILITY AREA that is of magnitude sufficient to possibly affect the reliable operation of the interconnection the RTO RC shall issue an alert to all CONTROL AREAS in its RELIABILITY AREA, and all RELIABILITY COORDINATORS within the INTERCONNECTION via the RCIS without delay.

3. Implementing relief procedures. If transmission loading progresses or is projected to progress beyond the OPERATING SECURITY LIMIT, the RTO RC will perform the following procedures as necessary:

3.1. Act to Relieve the Congestion. The RTO RC will act to relieve this congestion with all effective non-cost and off-cost measures (re-dispatch only within the current PJM zone). These measure many managing INTERCHANGE TRANSACTIONS through its respective CONTROL AREAS during this period to help mitigate the OPERATING SECURITY LIMIT violation.

3.2. Selecting transmission loading relief procedure. When the RTO RC experiences a constraint on a transmission system within its Reliability Area the RTO RC shall, at its discretion, select from either a “local” (Regional, Interregional, or sub regional) transmission loading relief procedure, an Interconnection-wide procedure or the RTO congestion management procedure.

3.2.1. Local transmission loading relief procedure. The **RTO RC** may use local transmission loading relief or congestion management procedures, provided the transmission system experiencing the constraint is a party to those procedures.

3.2.1.1. Use with an INTERCONNECTION-wide Procedure. The **RTO RC** may implement a local transmission loading relief or congestion management procedure simultaneously with an INTERCONNECTION-wide procedure. However, the **RTO RC** is obligated to provide the relief requested as directed by the INTERCONNECTION-wide procedure.

3.2.1.2. IDC Update. The **RTO RC** will enter into the IDC all INTERCHANGE TRANSACTION changes that result from the implementation of the local procedure.

3.2.2. INTERCONNECTION-wide loading relief procedure. The **RTO RC** may implement an INTERCONNECTION-wide procedure as detailed in the NERC Operating Manual Appendixes 9C1, 9C2, or 9C3.

3.2.2.1. Obligations. When implemented, the **RTO SC** shall comply with the provisions of the INTERCONNECTION-wide procedure. This may include action by RELIABILITY COORDINATORS in other INTERCONNECTIONS to, for example, curtail an INTERCHANGE TRANSACTION that crosses an INTERCONNECTION boundary.

3.3. Compliance with Interchange Policies. During the implementation of relief procedures, and up to the point that emergency action is necessary, the **RTO RC** and its member CONTROL AREAS shall comply with the Requirements of NERC Policy 3, "Interchange."

4. Implementing emergency procedures. The **RTO RC** has the authority to immediately direct the CONTROL AREAS and Transmission Operators, in its RELIABILITY AREA, to redispatch generation, reconfigure transmission, or reduce load to mitigate the critical condition until INTERCHANGE TRANSACTIONS can be reduced utilizing a transmission loading relief procedure, or other procedures, to return the system to a reliable state. The **RTO RC** shall coordinate these emergency procedures with other RELIABILITY COORDINATORS as appropriate. All member CONTROL AREAS shall comply with all requests from the **RTO RC** as authorized by the PJM Reliability Plan, operating agreements, and the PJM tariff.

VI. Transmission and Generation Outage Coordination

A. Transmission and Generation Maintenance – During this initial period (Dec '02 until Apr '03) the reporting of system outages will not change significantly.

- © PJM is the final authority for approving transmission outages to all facilities included in the PJM tariff.

1. Planned Transmission Maintenance

- 1.1 All Transmission Owners** shall submit their planned transmission maintenance schedules annually for the upcoming year.
- 1.2. Planned Transmission Maintenance** requests are submitted to the RTO RC for its approval at least three working days in advance of the scheduled outage.
- 1.3. The RTO RC** will coordinate with both the operations and planning personnel of the Transmission Owner for analysis and planning purposes when a transmission maintenance request is received.
- 1.4. The RTO RC** determines if and the extent to which, such planned transmission maintenance requests affect ATC, Ancillary Services, the security of the Transmission System, and any other relevant effects. This determination shall include appropriate analytical detail. After receiving a planned maintenance request the RTO RC either approves the request or denies the request and provides an acceptable time frame in which the maintenance can be approved.
- 1.5. The RTO RC** shall have the authority to revoke any previously approved planned transmission maintenance outage if forced transmission outages or other circumstances compromise the integrity or reliability of the Transmission System. The RTO RC shall notify the Transmission Owner of the decision to revoke approval of the maintenance as soon as possible after the circumstances arise that create the need for the revocation.
- 1.6. As Part Of Its Review Process** the **RTO RC** shall identify planned transmission maintenance schedules that limit ATC and, if necessary, shall identify opportunities and associated costs for rescheduling planned maintenance to enhance ATC.

- 1.7. **The RTO RC** shall document all planned transmission maintenance requests, the disposition of those requests, and all data supporting the disposition of each request, via its eDART system.

2. Unplanned And Emergency Transmission Maintenance

- 2.1. **The RTO RC** shall coordinate with the Transmission Owners to implement schedules for unplanned transmission maintenance. For emergency transmission maintenance, when conditions endanger the safety of employees or the public, or may result in damage to facilities, the Transmission Owners shall notify the **RTO RC** of such emergency maintenance. Approval by the **RTO RC** for such emergency transmission maintenance is not required.

3. Generation Maintenance. The RTO RC shall coordinate the maintenance of generating units, as appropriate, to minimize the affects of this maintenance on the reliability or capability of the PJM RTO Transmission system.

- 3.1. Subject to any necessary confidentiality arrangements, all Generation owners interconnected to the Transmission system shall submit their planned generating unit maintenance schedules to the PJM RTO one year in advance for a minimum two-year rolling period. These planned maintenance schedules shall be updated as necessary.
- 3.2. The **RTO RC** will coordinate generation maintenance schedules with the Generation Owners for analysis and planning purposes.
- 3.3. Subject to confidentiality arrangements, the **RTO RC** shall analyze planned generating unit maintenance schedules to determine their effect on the security of the PJM Transmission System.
- 3.4. The **RTO RC** shall coordinate procedures with nuclear generating facilities which will take into account planned transmission and generating unit maintenance scheduling criteria, limitations and restrictions to ensure the safety and reliability of operations.

4. Outage Coordination with MISO

- 4.1 PJM & MISO will mutually develop an interest list of transmission facilities operated by the other RTO whose outage has the potential to impact the reliable operation of their system.
- 4.2 PJM & MISO will exchange information on Planned Transmission Outage and Maintenance Transmission Outage Schedules for interested facilities.
- 4.3 PJM & MISO will develop a process to request, review, and if appropriate cancel transmission outages that would result in unreliable operation on the other parties system.

VII. Emergency Operating Procedures and Operating Guides

A. Emergency Operating Procedures

1. The RTO RC in coordination with its Reliability Monitoring Zones, Transmission Owners, state agencies, regional reliability councils, and other Reliability Coordinators, and in compliance with applicable state and federal laws and standards, has developed and will periodically update procedures for responding to emergencies. RTO RC has adopted the **PJM Emergency Procedures Manual** to serve as the Reliability Area procedures (Manual 12, which is available to all parties at pjm.com).

1.1. The **RTO Emergency Procedures** include procedures for responding to specified critical contingencies. These procedures will identify actions that the **RTO RC**, Transmission Owners, Transmission Users, and Generation Owners will take in response to disturbances that may develop into, a magnitude sufficient to affect the reliable operation of the Interconnection. These procedures are designed to address such conditions as: critically loaded transmission facilities, critical frequency deviations, or adverse voltage conditions. These procedures also address operations during Minimum Generation Events, Thunderstorms, Solar Magnetic Disturbances, Cold Weather Conditions, System Separation and Fuel Supply Disruptions.

1.2. The **RTO RC** or a Transmission Owner is required, by the PJM RTO as part of emergency planning, to continuously analyze system conditions that may cause interface or other operating limit violations including overloaded transmission lines and transformers, voltage and stability limits, etc., that require the initiation of emergency response actions. Such analysis shall be made at the **RTO RC's** initiative or at the request of a Transmission Owner, regional reliability councils, or other RTO's or Control Areas. The Emergency Procedures shall be amended to include any changes or additions resulting from such analysis.

1.3. The **RTO RC Emergency Procedures** make provisions for system restoration including priority restoration of off-site power to nuclear generating facilities.

2. The RTO RC shall direct the response to any emergency in the Transmission System pursuant to the Emergency Procedures in order to return the system to a reliable state. Individual Transmission Owners, Generation Owners, Transmission Users, and Control Areas shall carry out the required emergency actions as directed by the **RTO RC**, including generation re-dispatch, transmission reconfiguration, curtailment of interchange transactions, and the shedding of firm load, if required for regional security. Notwithstanding the above, the directed party is obligated to bring to the **RTO RC's** attention any safety and reliability impacts that may result from following the instructions.

3. In the event of an occurrence that is not covered by a specific Emergency Procedure the **RTO RC** has the authority to act and to direct actions of involved parties in order to mitigate the condition at hand.

4. Coordinated Emergency Procedures with MISO: The intent of PJM and MISO's coordinated emergency responses is to enhance reliability by leveraging both RTO's capabilities during an emergency.

4.1 The primary triggers for these coordinated responses include:

4.11 - TLR 5 and capacity deficient situations (EEA 2 and 3) such that curtailing firm schedules will result in capacity emergencies requiring load shed

4.1.2 - TLR 6 - If all IDC selected Firm Schedules have been curtailed and additional relief is required each RTO will be prepared to re-dispatch units to provide the required relief.

4.2 PJM and MISO will implement coordinated training and terminology in order to ensure a rapid and coordinated response to emergency conditions. Some of these preparations will include:

4.2.1 Conduct Annual Emergency Procedures Drill (Nov '02)

4.2.2 Agree to a common set of restoration priorities

4.2.3 Conduct Annual Restoration Drill (March '03)

4.2.4 Bi-Annual RC MISO/PJM Emergency Procedures Operator Certification Test

4.2.5 Annual System Operator Training on Selected Procedures and Lessons Learned

4.2.6 Semi-Annual Procedures Refresher training

4.2.7 Development of a MISO/PJM Operator Emergency Procedures Graphic Interface

B. Operating Guides

1. The **RTO RC** will continue to work with its Reliability Monitoring Zones (GROVEPORT, MAIN), and its Transmission and Generation owners to identify all existing local and regional operating guides. These existing guides and documents will be used in a portion of ECAR, MAIN, and MAAC, as appropriate, to address local transmission problems.

2. The **RTO RC** will also be responsible for the continued development, maintenance and implementation of a set of plans consistent with NERC Operating policies to cope with operating emergencies as defined in NERC Policy #6.

VIII. Functioning as a Single Reliability Area

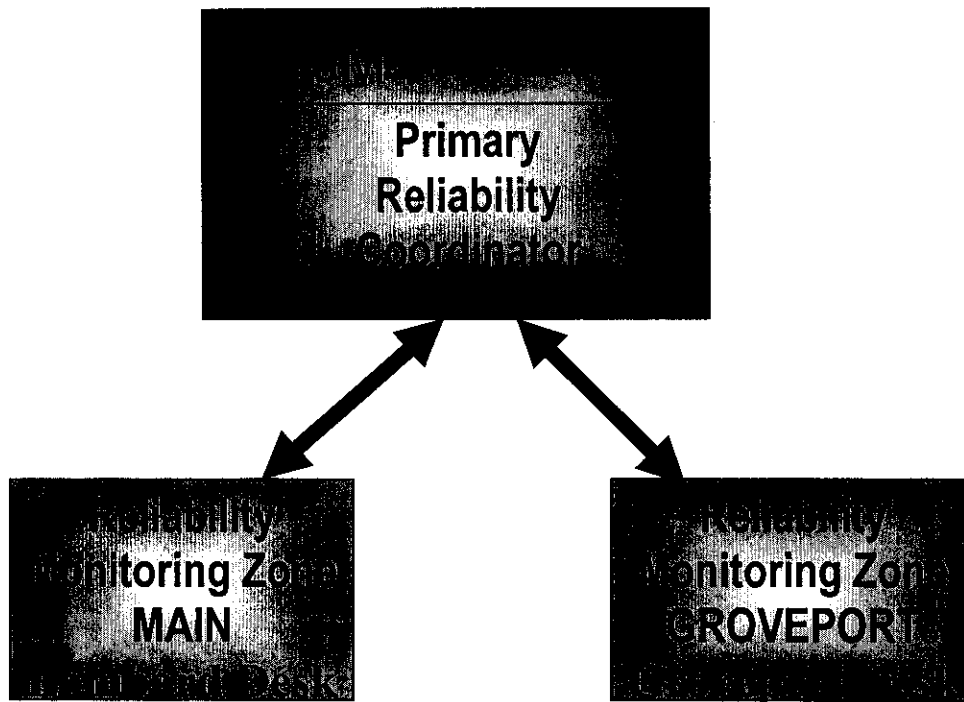
- A. PJM has functional control of the Transmission Owners' transmission facilities transferred to its control. PJM can exercise this authority in directing the owners to take actions with respect to these transmission facilities.
- B. The PJM Transmission Owner members, Transmission Members, and non- members in its Reliability Area presently include members of the ECAR, MAIN, and MAAC NERC Regions. These PJM members have requested PJM to operate as a single Reliability Coordinator for the entire RTO area. When requested, PJM will also provide Reliability Coordination services to Transmission Members and non-members.
- C. To effectively monitor and provide reliability coordination services, PJM will be divided into reliability-monitoring "zones". PJM will employ groups of Reliability Coordinators, one for each of the reliability- monitoring zones. There will be a Reliability Coordinator on duty in each of the reliability-monitoring zones 24 hours a day, 7 days a week at their respective Reliability Coordination Desks.

The current desks will include:

Reliability Monitoring Zone	Desk Title	Control Areas within Zone
PJM	PJM	PJM
GROVEPORT	Groveport	AEP, DP&L
MAIN	Lombard	ComEd, IP

- D. The reliability-monitoring zones are defined by groups of transmission/generation from the ECAR, MAIN, and the MAAC Regions where PJM is providing Reliability Coordination services.
- E. The number of reliability- monitoring zones and their boundaries will be adjusted, as appropriate, as new members join the PJM, and as the PJM agrees to provide reliability coordination services to nonmembers, or as PJM deems such change as necessary along logical electrical boundaries.

F. Graphically the composition of functions is depicted below:



G. Duties and Responsibilities:

a. Primary Reliability Coordinator (PJM)

- i. Primary responsibility to coordinate reliability actions; in order to ensure PJM operates as a single Reliability Area
- ii. Provides redundant monitoring of GROVEPORT and MAIN Reliability Monitoring Zones.
- iii. Remains abreast of all real-time security area and inter-regional operating issues
- iv. Coordinates Emergencies
- v. Emergency Conditions (EEA 2 & 3 Assistance)
 1. TLR 5 Events
 2. Restoration
- vi. Will assist in Regional and other RC coordination
- vii. Assists in on-shift dispute resolution (Attempts to provide solutions that can assist in providing optimum relief to the inter-security monitoring zone operating issues)
- viii. Approves any "unusual actions"

b. Reliability Monitoring Zone (MAIN & GROVEPORT):

- i. Provides Groveport and Lombard RC Desks for PJM
 - ii. Responsible for all monitoring and corrective actions for reliability inside GROVEPORT/MAIN areas respectively.
 - iii. Provides all information to PJM required to support Reliability Coordinator responsibilities
 - iv. Will Utilize TLR's for congestion management
 - v. Will work directly with respective CA's within Reliability Monitoring Zone
 - 1. Declare TLR's
 - 2. Issue Curtailments/Reloads
 - vi. Support NERC ISN, IDC, and SDX reporting requirements
 - vii. Will provide all information to PJM required to support Reliability Coordinator responsibilities.
- H. PJM as the RTO RC will have ultimate responsibility and authority to direct each of its Reliability Monitoring Zones; in order to maintain system reliability.
- I. Communications between RC and Control Area operators will be conducted, primarily, between the Control Area operators and the Reliability Coordinator assigned to their reliability- monitoring area.
- J. The PJM Reliability Coordinator is the Primary Reliability Coordinator. The Primary Reliability Coordinator will coordinate Reliability issues for the entire Reliability Area and provide direction to operations support staff as needed.
- K. Any unusual actions will be approved by PJM and will later be reviewed by the Manager, System Operations. Unusual actions would include directing emergency response and directing actions where Control Areas have not arrived at a consensus as to the appropriate actions required.
- L. All directives are subject to after the fact audits of the appropriateness of the directive. If necessary, the Reliability Coordinator, in consultation with the Primary Reliability Coordinator, may take immediate steps to stabilize adverse operating conditions that may develop, prior to notifying the Manager, System Operations. If time does not permit a Reliability Coordinator physically located in a separate office from the Primary Reliability Coordinator to consult with the Primary Reliability Coordinator, the Reliability Coordinator may immediately implement emergency directives in order to maintain reliability. Once actions have been implemented, the PJM Reliability Coordinators must communicate with

each other to make sure the entire PJM area is secure and will notify the Manager, System Operations of the event.

- M. PJM, the Primary Reliability Coordinator, will keep abreast of all real-time Reliability area and interregional operating issues and will be responsible to ensure that RC functionally operates as a single Reliability Area. The goal will be to resolve issues in a manner that does not advantage one reliability monitoring area over another.
 - a. For example, if two flowgates reach operating reliability limits simultaneously, the Primary Reliability Coordinator will evaluate required actions needed to relieve both flowgates and ensure that action taken to relieve one flowgate will not aggravate conditions on the other flowgate.
 - b. Likewise, if actions needed to relieve one flowgate will also relieve the other flowgate, the Primary Reliability Coordinator will choose the overall minimal relief to bring both flowgates within their operating Reliability limits.
- N. Each Reliability Coordinator will be knowledgeable of what is occurring in the other Reliability- monitoring areas and will be prepared to provide assistance.
- O. The Reliability Coordinators/Monitoring Zones will work together to evaluate relief options and the results of taking those options before they are implemented. The Reliability Coordinators will have access to the same information in each reliability-monitoring area of PJM, and therefore should reach consistent results.
- P. By operating as a single Reliability Area, constraints will be internalized as much as possible resulting in improved operations, coordination, and reliability.
- Q. PJM will work with all reliability monitoring areas, as necessary, to ensure that actions taken by Control Area operators and Reliability Coordinators within PJM are consistent with Reliability Area and interregional reliability objectives.
- R. The goal for all PJM Reliability Coordinators is to collaborate and operate as if they were in the same room and a single hand was operating the system.
- S. The PJM RC will adhere to all NERC Operating Policies and interregional "Seams" agreements.

IX. ECAR Specific Coordination Activities

A. The PJM RTO will become a member of ECAR, such that it can perform the RTO RC duties across the two regions. As a member of ECAR, the RTO RC will implement the following policies/procedures:

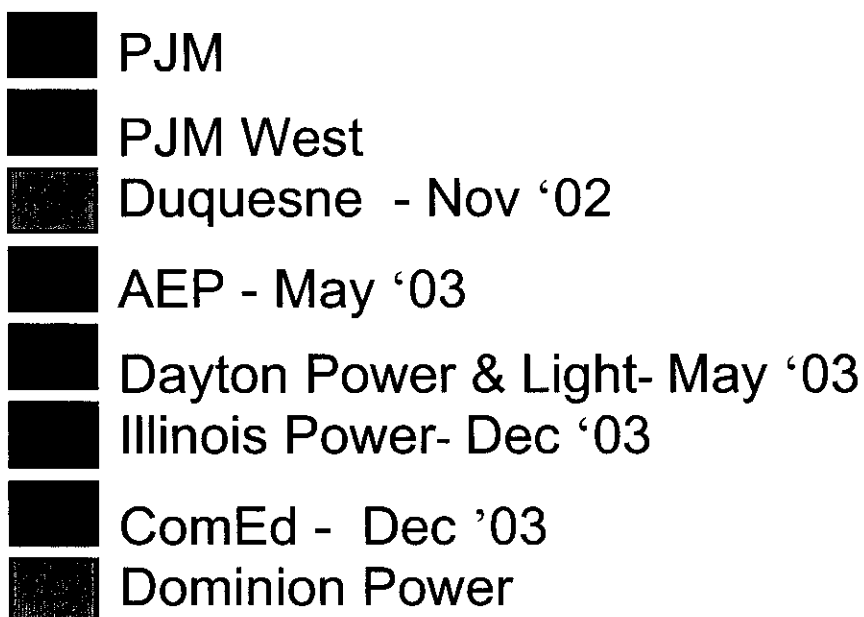
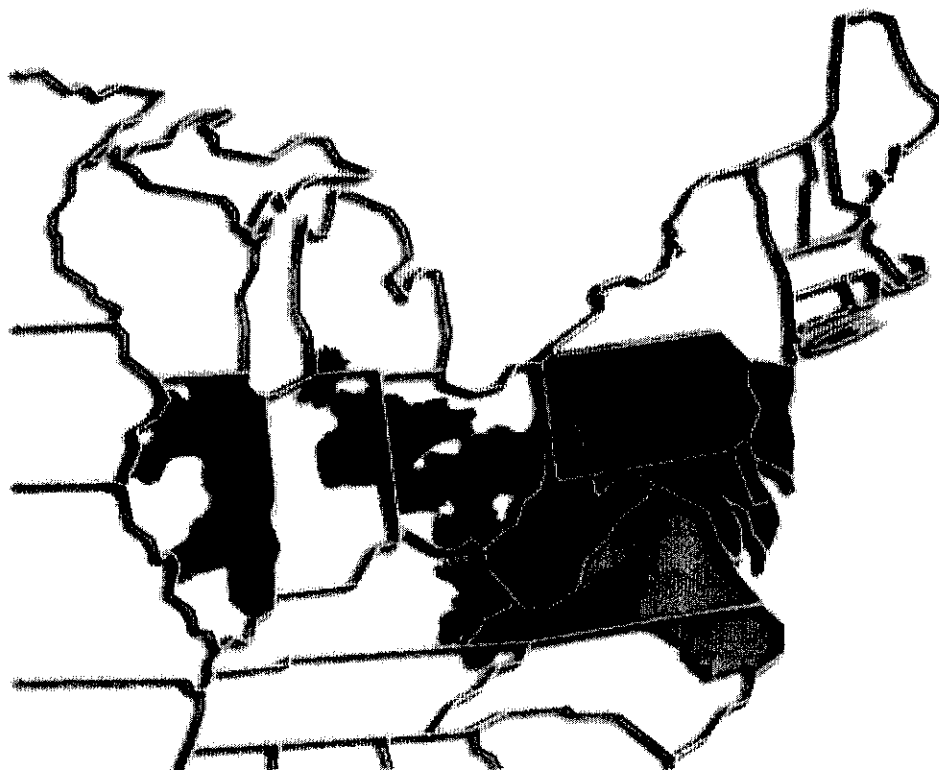
1. **Conference Calls:** Participate in the daily morning conference calls of all the RELIABILITY Coordinators that represent Control Areas for ECAR.
 - 1.1 PJM-will work with ECAR to identify the best way to implement a Hotline for all ECAR Control Areas and for all Reliability Coordinators that represent an ECAR Control Area
2. **Compliance:** PJM-West will help identify operating situations that will be investigated as part of the NERC mandatory compliance program. This will be done on the daily Reliability Coordinator conference calls.
3. **Audit Services:** PJM will provide audit services for all OASIS data requests involving data from AP after PJM-West begins operations (1/1/2002). PJM will not provide audit services for any OASIS data requests involving AP or DQ for data prior to 1/1/2002. PJM. AP has indicated that they will maintain OASIS data captured through 12/21/01 to meet auditing requirements.
4. **RC Services:** If requested, PJM-West will offer Reliability Coordinator Services, through the PJM West office, to other ECAR Control Areas on a contract basis.
5. **Operating Reserve:** The PJM Control Area will operate under the Operating Reserve policy of PJM. The Control Zone in PJM-West will operate under the Operating Reserve policy of ECAR. Thus, all of the Control Areas that are members of ECAR will follow the same Contingency Reserve Policy. The operation of the ECAR ARS system for PJM West control zone will be managed by the PJM West staff.
 - 5.1 PJM-will meet the requirements of ECAR Document 2 utilizing resources within the PJM West control area to provide Load and Frequency Regulation Reserve and resources within PJM and PJM West to meet the remaining reserve requirements
6. PJM-will perform the ACE monitoring for all member control areas that are part of the ECAR Inadvertent Settlement Tariff.

X. MAIN Specific Coordination Activities

A. The PJM RTO will fully utilize the current capabilities provided by the MAIN Reliability Coordinator Office :

1. **Conference Calls:** When requested by the MAIN office, PJM will participate in the morning conference calls of all the RELIABILITY Coordinators that represent Control Areas for MAIN.
2. **Compliance:** MAIN and PJM will help identify operating situations that will be investigated as part of the NERC mandatory compliance program. This will be predominately accomplished by the MAIN/Lombard Desk on its Reliability Coordinator conference calls.
3. **Audit Services:** To ensure independence PJM will be prepared to audit the MAIN Reliability Coordinator Monitoring Zone (RCMZ).
4. **RC Services:** If requested, PJM will offer Reliability Coordinator Services, through the MAIN office, to other MAIN Control Areas on a contract basis.
5. **Operating Reserve:** PJM will assist the MAIN RCMZ in ensuring that its control areas continue to operate under its *MAIN GUIDE NO. 1A "Operating Procedures During Operating Reserve Deficiencies"*.
6. **Emergency Procedures:** PJM will assist the MAIN RCMZ in ensuring that its control areas continue to operate under its *MAIN GUIDE NO. 1B Operating Procedures During Generating Capacity Deficiencies Causing Declining System Frequency or Separation*.
7. The MAIN RCMZ PJM-will perform the ACE monitoring for all member Control Areas that are part of the MAIN Inadvertent Settlement Tariff.

APPENDIX B: RELIABILITY AREA MAP



Market Growth Project Budget



Project Budget Summary

(dollars in millions)

	<i>Expense</i>	<i>Capital</i>	<i>Total</i>
Operations	\$10.2	\$18.9	\$29.1
Planning	0.7	1.3	2.0
Markets	8.7	16.2	24.9
eSuite	3.0	5.5	8.5
Telecommunications	2.0	4.4	6.4
Facilities	3.2	5.8	9.0
Information Technology Infrastructure and Testing	2.4	4.6	7.0
Other	5.2	5.9	11.1
Total	\$35.4 ⁽¹⁾	\$62.6 ⁽²⁾	\$98.0

(1) *To be paid by joining transmission owners in accordance with signed Implementation Agreements, reduced from \$36.4M due to selection of Illinois Power.*

(2) *Approved by PJM Board of Managers, original approval for \$63.6M reduced due to selection of Illinois Power.*

MAR 14 2003

PUBLIC SERVICE
COMMISSION

**COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION**

In the Matter of:)
APPLICATION OF KENTUCKY POWER)
COMPANY D/B/A AMERICAN ELECTRIC)
POWER FOR APPROVAL, TO THE)
EXTENT NECESSARY, TO TRANSFER) **CASE NO. 2002-00475**
FUNCTIONAL CONTROL OF)
TRANSMISSION FACILITIES LOCATED)
IN KENTUCKY TO PJM INTERCONNECTION,)
L.L.C. PURSUANT TO KRS 278.218)

**PREPARED TESTIMONY OF
ANDREW L. OTT
ON BEHALF OF PJM INTERCONNECTION, L.L.C.**

Q. Please state your name and business address.

A. My name is Andrew L. Ott, and my business address is PJM Interconnection, L.L.C., 955 Jefferson Avenue, Valley Forge Corporate Center, Norristown, Pennsylvania, 19403-2497.

Q. What is your current position with PJM Interconnection, L.L.C. (PJM)?

A. I have been employed since October, 1996 by PJM as its Executive Director of the Market Services Division. In that capacity, I am responsible for the management of the PJM Market Operations and Market Settlements. I am also responsible for development and oversight of PJM Market Design changes.

I. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is twofold. First, I will explain PJM's security constrained economic dispatch, locational marginal pricing (LMP), and financial transmission rights (FTRs). Secondly, my testimony provides the Commission with a market analysis of the impacts on the spot energy prices resulting from AEP, Dominion and Dayton Power & Light (DP&L) joining PJM. The market analysis examines impacts on an annual basis comparing the combined RTO market versus individual markets. Below, I discuss this market analysis, which is Attachment A, in greater detail.

II. PROFESSIONAL EXPERIENCE AND QUALIFICATIONS

Q. Please describe your prior professional experience.

A. For PJM, I was responsible for implementation of the current PJM LMP system, the PJM Financial Transmission Rights Auction and the PJM Day-ahead Energy Market. Prior to joining PJM, I have worked extensively in developing electricity market models and power system analysis applications. I have received a Bachelor of Science in Electrical Engineering from Penn State University and a Master of Science in Applied Statistics from Villanova University.

Q. Please summarize your work experience before joining PJM.

1 **A.** Prior to joining PJM, I worked for General Public Utilities Service Corp. for
2 thirteen years as a transmission planning engineer.

3 **III. OVERVIEW OF PJM's MARKET PRICING**

4 **Q.** How do PJM's markets differ from the wholesale electric market currently in
5 Kentucky?

6 **A.** The current wholesale electric market in Kentucky is a bilateral market. Hence,
7 market participants do not know what the prices are that other market participants are
8 paying for electricity in the wholesale market, unless the market participants voluntarily
9 reveal the pricing information. Conversely, PJM uses a transparent security constrained
10 economic dispatch with voluntary spot markets. Therefore, while market participants
11 will still be able to enter bilateral contracts or self schedule their own generation, they
12 will be able to see the prices in the bid based spot markets.

13 **Q.** What is a security constrained economic dispatch?

14 **A.** By participating in PJM, wholesale customers and the local utility can, if they so
15 choose, purchase the lowest-cost generation available to serve load in a given hour. This
16 can be done through the security constrained economic dispatch, which optimizes
17 generation every five minutes to meet load. Each wholesale customer can elect either to
18 participate in the spot market that is created through the economic dispatch or they can
19 elect to self-supply or bilaterally purchase energy to meet demand. In either case, the

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1 transparency of information provided by the spot market prices enables market
2 participants to make better economic choices in order to meet their supply and demand
3 requirements.

4 **Q.** What is economic efficiency and how is that significant in this market analysis?

5 **A.** When we refer to economic efficiency in the context of this market analysis we
6 refer to the best and most efficient use of resources and assets, such as generation and
7 transmission. The single energy market allows assets to be used in the most cost-
8 effective way possible, by allowing access to other providers in a transparent market.

9 Because information in the market is shared, market participants are free to choose the
10 most cost-effective means of supply and transmission to serve a load. The market
11 analysis's demonstrated savings are largely a direct result of this economic efficiency.

12 **Q.** What economic efficiencies does the market analysis evaluate?

13 **A.** The market analysis evaluates the increased efficiency of larger regional
14 scheduling and unit commitment, larger regional security-constrained economic dispatch,
15 and increased efficiency in interregional transmission utilization to support economic
16 power transfers.

17 **Q.** How is congestion handled today in a non-market based system?

18 **A.** In a non-market based system, when utilities experience congestion on their
19 transmission system, they redispatch generation in order to clear the congestion. The

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1 costs of that redispatch are traditionally borne by the company's retail and wholesale
2 customers through fuel adjustment clauses, contractual arrangements for wholesale
3 customers and through base rate changes. If congestion is caused by unscheduled power
4 transfers, utilities will utilize North American Electric Reliability Council's Transmission
5 Loading Relief procedures to curtail power flows.

6 **Q.** What is the LMP based energy market?

7 **A.** An LMP based energy market utilizes the same security-constrained economic
8 dispatch software that is used to operate power systems today. The LMP based market
9 simply displays the energy prices at each demand and supply location that have always
10 been incurred in a transparent manner so that all wholesale market participants can react
11 more efficiently to the price signals. Under the LMP system, each generator supplying
12 energy to the bid-based energy exchange market is paid the marginal price of generation
13 at each location on the grid. The use of LMP reflects the opportunity cost of using
14 congested transmission paths and encourages efficient use of the transmission system.

15 **Q.** Please explain how Load Serving Entities (LSEs) can use FTRs to offset
16 congestion charges?

17 **A.** FTRs are, in essence, an insurance policy which protects the holder from
18 incurring the costs of congestion over a given transmission path. PJM allocates FTRs to
19 Network and Firm Point-to-Point transmission customers, including a utility's native load

1 customers. FTRs are allocated to these native load customers to recognize that they have
2 paid the fixed cost of the transmission facilities through their payments of transmission
3 service demand charges. These FTRs are allocated to the firm transmission customers
4 based on a set of allocation rules that allow the customers to request FTRs from their
5 generation resources to their demand locations. Since transmission congestion charges
6 are determined by differences in locational prices between a customer's generation
7 resources and demand locations, FTRs act as a hedge against the payment of these
8 congestion costs. Typically, LSEs can use a transmission congestion hedging strategy
9 that includes bilateral energy contracts and FTRs to protect themselves against incurring
10 congestion charges. PJM will be implementing an auction system for FTRs but will
11 continue to ensure protection for native load customers by allocating to customers the
12 revenue proceeds from the auction. In this way, an entity serving native load customers
13 can protect those customers from incurring any additional costs from congestion.

14 **IV. OVERVIEW OF THE MARKET ANALYSIS**

15 **Q.** Has PJM performed a market analysis of forming a larger regional energy
16 market?

17 **A.** Yes, PJM has performed an analysis, specifically a market analysis of PJM
18 Market Growth for AEP and Dominion, and an analysis of the impact on spot energy
19 prices. The market analysis is provided as Attachment A to my testimony.

1 **Q.** What was your role in the development of the market analysis?

2 **A.** I directed the production of the market analysis.

3 **Q.** Have you performed similar market analyses?

4 **A.** Yes. At the request of the Maryland Public Service Commission, I produced a
5 similar study on the impacts of the formation of the Northeast RTO (NERTO).

6 **Q.** Please describe the market analysis contained in Attachment A.

7 **A.** The objective of the market analysis was to compare regional spot market energy
8 prices both with and without the participation of AEP, Dayton Power & Light and
9 Dominion in an RTO. AEP, Dayton Power & Light and Dominion were chosen for this
10 analysis because all three companies have announced their intention to join PJM. The
11 AEP comparisons, both with and without an RTO are the relevant numbers for the
12 Kentucky PSC. I also discuss the full results of the analysis for completeness. The
13 methodology used in the market analysis undertakes an annual view and considers the
14 combined RTO market versus individual markets.

15 The market analysis considers the economic benefits of forming a larger regional
16 energy market as well as any increases in the cost of transmission congestion under the
17 LMP-based energy market. The market analysis assumes that the PJM/PJM West, AEP,
18 DP&L and Dominion control areas will be included in a single energy market.

1 **Q.** What does the market analysis show are the benefits of forming a larger regional
2 energy market in the AEP region?

3 **A.** The potential savings to LSEs that result from implementing a single energy
4 market place in a larger RTO are significant. The savings are shown, in Table 1 of
5 attachment A, for load payments, generation production costs, and generator revenues.
6 The combined RTO energy market savings in comparison to the current paradigm, in
7 which each utility dispatches its own system and enters bilateral contracts, are: \$932
8 million for load payments; \$294 million for generation production costs; and \$850
9 million for generator revenues.

10 The potential annual savings to wholesale load serving entities (LSEs) in AEP's
11 service territory are from \$61 to \$80 million. These results are for the entire AEP service
12 territory. The range between \$61 to \$80 million in annual savings is dependent upon
13 what portion of the actual market is bilateral and what portion is on the spot market. The
14 results could actually show greater savings depending on the assumptions that are
15 considered for bilateral transactions.

16 The LSE operating within an RTO should see decreased generation production
17 costs (compared to the market prior to the implementation of the RTO) due to the
18 increased efficiency in the market. The decreased production costs may be offset by
19 increased power purchases; however, LSEs operating in a transparent market will be able

1 to purchase power at a competitive price which will result in net savings. Because no
2 entity should rely solely on the spot market nor would a generator sell at its marginal cost
3 every hour of the year, this range is presented with full disclosure that annual savings
4 would be between \$61 million to \$80 million if a transparent wholesale market were
5 instituted. If we assume that today's wholesale bilateral contracts are struck at marginal
6 prices in the wholesale marketplace both today and in the future, then savings will
7 increase.

8 **V. OVERALL MARKET ANALYSIS CONCLUSIONS**

9 **Q.** How does PJM present the results of the market analysis?

10 **A.** PJM presents the results in several forms to make the information as meaningful
11 as possible. The values in the report are provided for the entire year of simulation, and
12 are listed in Table 1 of Attachment A. The results are presented based on generation
13 production cost and purchased power costs and based on spot market prices that occurred
14 in each hour of the simulation.

15 **Q.** Please explain the term Generation Production Cost.

16 **A.** The Generation Production Cost is the cost to operate the generator at the desired
17 level of output for each hour. These costs include hourly fuel costs, operation and
18 maintenance costs, start up costs, and emissions costs. When considering generation
19 production costs, the market analysis compares generation production costs and the cost

1 of purchased power (assuming that bilateral contracts are in place and control the rates
2 for purchased power). This allows us to look at the market from the point of view of how
3 much is the cost for providing the power.

4 **Q.** Please explain the term Net Purchased Power Cost.

5 **A.** The Net Purchased Power Cost is defined as the cost of power purchases or the
6 revenue from power sales at the bilateral contract price. As I explained earlier in my
7 testimony, the larger regional market allows for greater competition for purchased power
8 and results in the cost of purchased power being lowered; in turn this can allow
9 generators to produce power more efficiently. This results in an overall lowering of the
10 cost of service for a generator.

11 **Q.** Please explain the term Load Payments.

12 **A.** Load Payments are defined as the product of the hourly energy (MWh) consumed
13 at each location and the hourly LMP at that location. A load payment is the hourly
14 energy (MWh) consumed at each location, multiplied by the hourly LMP at that location
15 (LMP is expressed as \$ per MWh). The resultant amount is the actual total value of LMP
16 paid in a given hour.

17 **Q.** Please explain the term Generation Revenue.

1 **A.** Generation revenue is defined as the hourly energy (MWh) output for each
2 generating unit multiplied by the hourly LMP at the generator's location. The resultant
3 amount represents the actual revenue received at each location, at each hour.

4 **Q.** Does the market analysis consider the possibility of increased costs?

5 **A.** Yes, as I stated earlier in the testimony, the market analysis considers the cost of
6 transmission congestion under the LMP-based energy market. The magnitude of
7 transmission congestion that occurs in the simulation is the result of the locational price
8 differences between demand and supply locations and is called transmission congestion
9 charges.

10 The charges can be viewed as the cost of transportation to deliver energy from a
11 source location to a demand location. Congestion costs exist in the market today and
12 they are borne disproportionately by retail customers through the retail fuel adjustment
13 clause or in base rates. In the single energy market load serving entities would also
14 receive FTRs. The LSEs are able to offset all of their congestion charges with FTR
15 credits.

16 **Q.** Does the Market analysis consider the cost of obtaining reserve requirements?

17 **A.** Yes, the cost of procuring reserves is included in the market analysis results. The
18 production cost model that is used in the analysis takes into account the reserve
19 requirements that currently exist for each control area.

1 **Q.** Are the results contained in the market analysis applicable for the Commonwealth
2 of Kentucky?

3 **A.** Yes. However, the market analysis shows the savings for the entire AEP system.
4 The portion of those total savings will be allocated to Kentucky customers pursuant to the
5 AEP Operating Agreement and its cost allocation processes.

6 **Q.** Does this market analysis demonstrate actual benefits of a large regional energy
7 market for end-use consumers?

8 **A.** Yes. End-use customers can most certainly benefit from the cost savings that
9 result from the large regional energy market. The economic efficiencies that are gained
10 by meeting demand through a larger regional security-constrained economic dispatch are
11 significant and the efficiencies translate into significant savings. The savings are the
12 result from reductions in overall generation production costs as well as more efficient
13 utilization of transmission system capability.

14 **VI. MODELING FOR THE MARKET ANALYSIS**

15 **Q.** How was the analysis in the market analysis performed and what model was used
16 for the market analysis?

17 **A.** The methodology chosen to perform generation production cost analysis is the GE
18 MAPS software which can perform simulations on security-constrained unit commitment
19 and economic dispatch. The model provides a realistic estimate of the impact of a larger

1 regional market because it is based on the same security-constrained unit commitment
2 and economic dispatch algorithms that are in use today by AEP and PJM.

3 The individual market simulations were performed by modeling the individual
4 control areas with separate unit commitment and dispatch functions (multi-pool
5 operation). Historic levels of energy trading were simulated. This model simulates
6 current operating conditions where each control area performs least-cost unit
7 commitment and economic dispatch to meet demand.

8 **Q.** How was the impact of implementing a single energy market in a larger regional
9 RTO measured?

10 **A.** The analysis follows the example of a single power pool operation. The impact
11 of a larger regional RTO was measured by combining and modeling the operation of all
12 of the control areas under a single generation commitment and dispatch, like a single pool
13 operation. These results are then compared to the individual market simulations to
14 quantify the impact of the larger regional market on spot market prices and on generation
15 production costs.

16 **Q.** Is the model that was used a standard model that has been tested and used in other
17 studies?

18 **A.** Yes. The MAPS/MW flow program was used in several recent studies, such as
19 the SEARUC Cost-Benefit Study and PJM's NERTO study of the benefits of larger

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1 regional energy markets. The methodologies used in this market analysis may be applied
2 to other market analyses and scenarios because the program simulation considers the
3 operating characteristics of individual generating units on the system. Therefore
4 generating units can be substituted or their characteristics changed and then the analysis
5 can be rerun.

6 **Q.** Does this conclude your testimony?

7 **A.** Yes it does.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY POWER COMPANY)
d/b/a AMERICAN ELECTRIC POWER FOR)
APPROVAL, TO THE EXTENT NECESSARY,) Case No. 2002-00475
TO TRANSFER FUNCTIONAL CONTROL OF)
TRANSMISSION FACILITIES LOCATED IN)
KENTUCKY TO PJM INTERCONNECTION, L.L.C.)
PURSUANT TO KRS 278.218)

AFFIDAVIT

Andrew L. Ott, upon first being duly sworn, hereby makes oath that if the foregoing questions were propounded to him at a hearing before the Public Service Commission of Kentucky, he would give the answers recorded following each of said questions and that said answers are true.

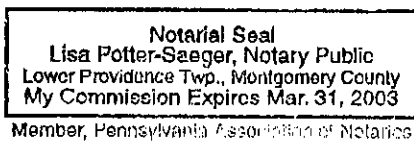

ANDREW L. OTT

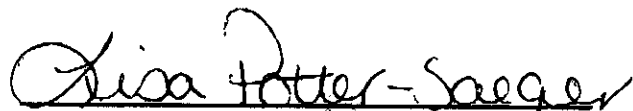
STATE OF PA)

COUNTY OF Montgomery)

SUBSCRIBED, SWORN TO AND ACKNOWLEDGED before me, a Notary Public, by Andrew L. Ott, this 14th day of March, 2003.

My commission expires: March 31, 2003




NOTARY PUBLIC



**PJM Market Growth
For AEP and Dominion
Analysis of Impact on Spot Energy Prices**

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Introduction

Some of the former Alliance members, American Electric Power (AEP), Dominion, Dayton Power and Light and Commonwealth Edison have indicated their intention to become integrated into the PJM RTO. The Virginia State Corporation Commission has requested that the PJM staff begin an investigation of the economic aspects of integrating Dominion and AEP into the PJM RTO energy market. The following two areas were identified in the request:

1. Perform an analysis to determine economic benefits of forming a larger regional energy market by evaluating economic efficiency gains that could be realized through:
 - Increased efficiency of larger regional scheduling and unit commitment,
 - Increased efficiency of larger regional security-constrained economic dispatch and
 - Increased efficiency in interregional transmission utilization to support economic imports.
2. Investigate any increases in the cost of transmission congestion under the LMP-based energy market

PJM has performed a preliminary analysis to investigate these impacts. This report summarizes the methodology and the results of the analysis that have been concluded at this time. These analysis results and the study methodology are under review by Dominion and by AEP.

Analysis Methodology

The objective of this analysis was to estimate the impact of implementing a larger Regional RTO market on the regional spot market energy prices in the near term (i.e., within the next several years). This analysis assumed that the PJM/PJM West, AEP, Dayton and Dominion control areas would be included in a single Regional RTO operating a single energy market. The analysis was performed using the General Electric Multi-Area Production Simulation (MAPS) program. The database used to perform the analysis was purchased from the General Electric Power System Energy Consulting function which maintains the database using publicly available data sources.

The MAPS/MW flow program is a commonly-used production costing model.¹ This program calculates hour-by-hour production costs while recognizing constraints on generation dispatch that are imposed by the transmission system. The program uses a detailed electrical model of the entire transmission network, along with generation shift factors determined from a solved AC powerflow model, to calculate the power flows for each hourly generation dispatch in the simulation. The program provides production costing results and hourly spot prices at individual buses and flows on selected transmission lines. The MAPS program formulates the generating system dispatch as a linear programming problem where the objective function is to minimize production costs subject to electrical constraints. The objective of the commitment and dispatch algorithms is to determine the most economic operation of the generating units on the system. The simulation is subject to the operating characteristics of the individual generating units, the constraints imposed by the transmission system, and operating and spinning reserve requirements.

The methodology of using GE MAPS to perform generation production cost analysis was chosen because it can perform simulations based on security-constrained unit commitment and economic dispatch. This program can simulate both a generation dispatch to serve load and a Locational Pricing-based market by using the security-constrained economic dispatch feature to

¹ The MAPS/MW flow program was used in several recent studies such as the SERUC Study and the NERTO study to analyze the benefits of larger regional energy markets.

match load and generation on an hourly basis and to calculate hourly market clearing prices. This approach provides a model that can simulate realistic economic dispatch scenarios and market operating conditions using a full transmission model and using realistic generation operating constraints. Thus, this analysis provides a reasonable estimate of the impact of the formation of a larger regional market by comparing results from simulations of the individual existing entities (the PJM market, the AEP control area and the Dominion control area) where security-constrained economic dispatch is used to meet control area demand to results from simulations of a combined Regional market including all of these areas where security-constrained dispatch is used to meet the entire market demand.

The individual market simulations were performed by modeling the individual control areas with separate unit commitment and dispatch functions (multi-pool operation). In this mode, economic transactions between the control areas were also modeled to simulate historic levels of energy trading between the markets. This simulation was intended to model operating conditions that are similar to the current operations in which each control area performs its own least-cost unit commitment and economic dispatch to meet the control area demand requirements.²

The combined RTO market simulations were performed by modeling operation of the all of these control areas under a single generation commitment and dispatch (single pool operation).

The results of the simulations performed throughout this analysis can be presented in several different ways. One way to report results is by comparing generation production costs and purchased power costs (at an assumed bilateral contract price). This type of comparison was provided in this analysis and it can be used to quantify the impact of a larger regional market from a cost of service point of view. Another way to present results is to assume market activity based on the wholesale market rules. The wholesale market results provided in this analysis assumed the use of PJM Market Rules across the region, including the Locational Marginal Pricing

² The production cost model included reserve requirements that currently exist in each control area; therefore, the cost of procuring reserves was implicitly included in the results.

form of transmission congestion management. The PJM rule set was chosen because the current implementation agreements are based on the current PJM market design. In a Locational Marginal Pricing market, demand pays the Locational Marginal price at its location for all energy consumed (these are Load Payments) and generation receives the Locational Marginal price at its location for all energy injected into the system (these are generation revenues). Energy deliveries pay transmission congestion charges based on Locational Price differences between the source and sink of the transaction.

These results of these simulations provided the ability to compare the impact of the formation of a larger regional market from both a cost of service point of view and from a marginal pricing point of view.

Overview of the Base Case Scenario

The year 2004 was chosen as the simulation year because 2004 is scheduled to be the first full year of operation of the expanded PJM RTO energy market. The Base Case scenario, Scenario 1, was intended to model average system conditions with normal weather-based load forecasts, average generation availability, average historic values of energy transfers and average fuel costs. A more detailed description of the assumptions for Scenario 1 is outlined in the Appendix.

After establishing a realistic Base Case scenario, sensitivity analysis can be performed to measure the impact of changing various Base Case assumptions on the overall results. Under this type of analysis, it is helpful if only one assumption is changed in each of the sensitivity analysis scenarios so that the effect of the assumption on the results could be isolated and measured.

Analysis Results

The results for this analysis are presented both based on generation production cost and purchased power costs and based on the spot market prices that occurred in each hour of the simulation. The spot market prices

are the Locational Marginal prices at each generation bus and load bus on the electric network. Since the market analysis was based only on spot market prices and did not include some estimate of the impact of bilateral trading contracts, it is important to present the results in several ways to provide enough information to make the results meaningful to PJM stakeholders. The results are presented in the following forms:

Generation Production Cost - The generation production costs are the costs to operate the generation at the desired level of output for each simulation hour. The generation production cost was defined as summation of the hourly fuel cost, operation and maintenance cost, start-up cost, and emission cost for each thermal generating unit when dispatched at the simulated MWh output level. The values reported under “Combined RTO Total” in the results tables are the summation of the hourly generation production cost over the entire year of simulation for the individual market simulations.

Net Purchased Power Cost – These purchased power costs are defined as the cost of power purchases or the revenue from power sales at the bilateral contract price. The bilateral contract price was calculated based on the difference between production cost and marginal cost to serve load using a split savings approach.

Generation Revenue - The generation revenue was defined as the product of the hourly energy (MWh) output for each generating unit and the hourly LMP at the generator’s location. The values reported under “Combined RTO Total” in the results tables are the summation of the hourly generation revenue over the entire year of simulation.

Load Payments - The load payments were defined as the product of the hourly energy (MWh) consumed at each location and the hourly LMP at that location. The values reported under “Combined RTO Total” in the results tables are the summation of the hourly load payments over the entire year of simulation.

The estimated impact of implementing a single energy marketplace in a larger Regional RTO was measured by comparing the difference in generation production cost, generation revenue, and load payments for the two modes of market operation (individual control areas versus a combined RTO energy market). The values reported in the tables under the column heading "Combined RTO Change" are the difference between the totals for the combined market simulation and the individual market simulation (Change = Combined market total – Individual market total). The values reported under "PJM Change", "Dominion Change" and "AEP Change" are the differences between the combined market simulation and the individual market simulation for the PJM/PJM West control areas, the Dominion control area and the AEP control area respectively.

The net generation profits can be calculated from these results by subtracting the generation revenue from the generation production cost.³ The results of the base case scenario are shown in Table 1.

	Combined RTO Total	Combined RTO Change	AEP Change	PJM Change	Dominion Change
Load Payments	\$15,4014	- \$932	- \$61	- \$202	- \$669
Generation Production Cost	\$9,935	- \$294	\$340	- \$339	- \$295
Net Purchased Power Cost	-	-	-\$420	\$114	\$169
Generator Revenues	\$14,960	-\$850	\$570	-\$468	-\$952

³ As stated above, this analysis did not attempt to estimate the impact on the results of assuming some amount the generation profits flow back to load through bilateral trading contracts.

Note: All values are in millions of dollars

Table 1: Base Case Scenario

The results illustrated in Table 1 may be utilized to perform a variety of comparisons to quantify the impact of the formation of a larger regional market. If one assumes a cost of service retail environment, both before and after the implementation of a the regional wholesale market (i.e. power is transacted at its marginal cost rather than a market clearing price), then the potential annual savings to wholesale load serving entities in Dominion is in the range \$120 million in the one-year simulation based on measuring the reduction in generation production cost and offsetting it with the increased payments for purchased power. The purchased power payments increase because the energy that is not generated by Dominion is replaced with power purchases. If, on the other hand, we assume that today's wholesale bilateral contracts are struck at marginal prices in the wholesale marketplace both today and in the future, then the savings to wholesale load serving entites would approach the change in load payments of \$669 million. Likewise, the potential annual savings to wholesale load serving entities in the AEP service territory is \$61 to \$80 Million. Because no entity relies solely on the spot market nor would a generator just sell at its marginal cost every hour of the year, this range is presented with the understanding that the annual savings to load serving entities that are serving retail customers would be somewhere between these two numbers depending upon the bilateral transaction assumptions that are utilized.

These results indicate that MWh weighted clearing prices reduced on an aggregated regional basis which demonstrates a net cost savings for load in the combined market simulation relative to the individual market simulation.

Transmission Congestion

The simulations that were performed in this analysis are based on a complete transmission model and on a security-constrained economic dispatch algorithm with the capability to model reactive transfer limits and single contingency thermal limits. Therefore, it is possible to utilize the results of these simulations as an indicator of the amount of transmission congestion that may occur upon implementation of the larger regional market. The magnitude of transmission congestion that occurred in the simulation can be quantified in terms of the locational price differences between demand and supply locations in each hour of the simulation. These price differences multiplied by the MWh of power transferred between the supply and demand locations are called transmission congestion charges. Therefore, the transmission congestion charges are the transportation costs that are generally paid by consumers to deliver the energy from the source location to the demand location. It should be remembered that congestion costs exist in these regions today and they are borne disproportionately by retail customers through the retail fuel adjustment clause or in base rates.

Financial Transmission Rights (FTRs) can be acquired by Load Serving Entities under Network or Firm Point-to-Point transmission service to act as a protection mechanism against increased costs due to transmission congestion. For LSEs who purchase Network transmission service, FTRs may be acquired from their generation resources to their demand locations. The amount of the FTR credit is driven by the locational price differences between supply and demand locations and by the MW amount of FTRs held. Since the FTR provides a credit to the holder, they can offset congestion charges that are incurred by transporting energy on the same or similar transmission paths.

The transmission congestion charges that were paid by load customers in the combined market simulation are shown in Table 2. Also included in Table 2 are the transmission congestion credits that would be received by the LSEs based on their allocation of FTRs. In this analysis, the LSEs were assumed

to have requested FTRs up to their peak load from the designated generation capacity resources that historically have served the load in each area.

Table 2 – Transmission Congestion Charges and FTR Credits for LSEs in the Combined Market Simulation

	Combined RTO Total For LSEs	AEP LSEs	PJM LSEs	Dominion LSEs
Transmission Congestion Charges	\$263	\$14.7	\$201.8	\$46.5
Transmission Congestion Credits	\$269.5	\$15.1	\$205.8	\$48.6

Note: All values are in millions of dollars

These results indicate that the transmission congestion charges that are paid by LSEs to serve load would be entirely offset by the LSEs FTR credits based on the assumption the LSEs requested FTRs from their generation supply resources to their aggregate demand locations.

Appendix

Base Case Assumptions

The base system assumptions included a simulation for the year 2004. The annual peak-hour demand and annual energy demand for the regions were developed from the NERC Electricity Supply and Demand Database (2000 release). Hourly load data from 1997 was used to build hourly load shapes. The peak loads and annual energy are applied to the hourly load shapes for the three regions. The values used for the simulations are shown in Table 3.

Table 3 – Annual Energy and Peak Demand

Electricity Demand	PJM ⁴	AEP	Dominion
2004			
Annual Energy (GWh)	342200	124900	79530
Peak Demand (MW)	65300	21800	15630

The installed generating capacity for 2004 was based primarily on the generating unit information contained in the RDI Basecase database (August 2000 release). The generation addition's for 2004 included 2700 MW in PJM, 9400 MW in ECAR Region, and 2100 MW in VACAR Region.

The generation offer data were based on estimates of the generation marginal costs from RDI (August 2000 release) for 2004. These data were derived from a set of 2001 annual average fuel prices that were escalated to 2004 using the following escalation factors:

Coal – 1.0167 per year,
Oil – 1.02 per year,
Gas – 1.0345 per year.

⁴ PJM included the PJM and the PJM West regions. PJM West included the Allegheny Power region. The PJM and PJM West results were reported together in this analysis because they are currently operated as a single energy market.

The same escalation rates were used for generation in the PJM, AEP, and Dominion areas. The set of annual average fuel prices was used throughout this analysis and was obtained from the RDI Basecase (February 2000 release). The fuel prices used for the simulations are shown in Table 4.

Table 4 – Fuel Prices for 2001

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
Coal	\$1.39	\$1.38	\$1.37	\$1.36	\$1.35	\$1.35	\$1.36	\$1.36	\$1.35	\$1.34	\$1.35	\$1.36
Nuclear	\$0.52	\$0.52	\$0.52	\$0.52	\$0.52	\$0.52	\$0.52	\$0.52	\$0.52	\$0.52	\$0.52	\$0.52
Distillate	\$5.23	\$6.14	\$5.71	\$5.39	\$5.82	\$5.27	\$5.71	\$5.94	\$5.04	\$5.42	\$6.80	\$6.41
Oil	\$4.58	\$3.82	\$3.36	\$3.45	\$3.44	\$3.39	\$3.50	\$3.83	\$4.05	\$4.23	\$4.28	\$4.04
Residual	\$4.39	\$3.86	\$3.54	\$3.43	\$3.50	\$3.41	\$3.35	\$3.28	\$3.29	\$3.57	\$4.18	\$4.47
Oil												
Natural												
Gas												

Operation and Maintenance (O&M) costs were developed by PSEC in 1997 and 1999. Table 5 shows a summary of the range of the values applicable to generation plants in the PJM, Dominion and AEP regions.

Table 5 – Operation and Maintenance Costs

	Variable Costs (\$/MWh)	Fixed Costs (\$/MWh)
Nuclear	0.6	75
Gas Turbines	1.5 – 4.0	3.0 - 6.0
Steam		
Turbines	0.6 - 1.4	10.6 - 23.9
Combined		
Cycles	1.2 - 1.5	10.0 - 12.0

The generation outage rates included both maintenance outages and forced outages based on historic analysis using NERC GADS data for the period 1993-1997. Table 6 shows the outage rates used in the simulations.

Table 6 – Generation Outage Rates

Unit Type	Size(MW)	Planned Outage Rate	Forced Outage Rate
Nuclear	All	10	6
Fossil-Coal	0-99	9.6	4.8
	100-199	10	5.7
	200-299	10.6	6.1
	300-399	11.6	8.2
	400-599	11.9	8
	600-799	9.8	6.4
	800-999	9.7	5.9
	>=1000	12	7.7
Fossil-Oil	0-99	7.6	4.6
	100-199	10	5.6
	200-299	11	9.6
	300-399	13.4	6.9
	400-599	13.4	5.4
	600-799	14.4	7
	800-999	8.1	5.1
Fossil-Gas	0-99	6.4	4.2
	100-199	10.2	5.3
	200-299	12.4	3.8
	300-399	15.2	6.7
	400-599	13.2	5.4
	600-799	14.2	6
	800-999	10.5	6.1
GT	All	6.3	4.3
CC	All	10.5	3.3

The plant emission rates for large coal plants in PJM were derived using 1998 Continuous Emissions Monitoring System (CEMS) data. Default emission rates were used where specific information was not available. The default values used for the analysis are shown in Table 7.

Table 7 – Default Emissions and Heat Rates

	Default Emissions & Heat Rates						
	Full Load Heat Rate (MBTU/KWh)				Release Rates (lbs/MBTU)		
	<100 MW	100-250 MW	250-500 MW	>500 MW	SO ₂	CO ₂	NO _x
Coal-Fired Steam Boilers	11970	10950	10800	10400	1.38	205	0.48
Heavy Oil-Fired Steam Boilers	13370	11060	11990	10970	0.91	160	0.27
Natural Gas-Fired Steam Boilers	11860	10350	9970	9340	0	119	0.2

A full network transmission model of PJM, ECAR, and VACAR for year 2004 was used for the analysis. Normal and single contingency constraints were modeled for the EHV transmission system in addition to major transmission interfaces in the three regions. The voltage-based transfer limits were modeled based on pre-contingency flow limits that are calculated from the system voltage characteristics using an AC powerflow analysis.